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October 12, 2018

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. ER19-105-000
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] which will have the effect of significantly lowering prices on that curve at all capacity levels, compared to the VRR Curve used in the May 2018 RPM capacity auction. 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.

PJM requests that the enclosed revisions become effective on December 12, 2018, which is 61 days after the date of this filing.[2]

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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 As described in Section II.C.5 herein, PJM is proposing to use the CONE value that accounts for major maintenance costs being included in cost-based offers in the energy market, rather than in the capacity market. PJM intends to file revisions to Operating Agreement, Schedule 2 as well as Tariff, Attachment DD, section 6.8 in the near term to clarify those sections of the Operating Agreement and Tariff accordingly.

I. INTRODUCTION AND SUMMARY

Under the Tariff, PJM and its stakeholders undertake a periodic review of the shape of the VRR Curve[3] used to clear the RPM Auctions and key inputs to that curve, i.e., the Cost of New Entry ("CONE")[4] by a representative new power plant and the Net Energy and Ancillary Services Revenues[5] ("EAS") that plant would be expected to earn in the PJM markets.

Reflecting the outcome of that Tariff-prescribed process, the PJM Board directed PJM to submit this filing revising the PJM Tariff to:

- shift the downward-sloping VRR Curve to the left by 1%, given that the market and supply uncertainties PJM showed in the 2014 RPM parameter review that warranted a prudent 1% rightward shift, have largely been resolved;
- update the estimate of the Gross CONE (reducing that estimate by over 20% in all areas of the PJM Region), based on a detailed comprehensive analysis of the construction, operation, and capital costs of the combustion turbine ("CT") peaking plant Reference Resource;
- update the definition of the Reference Resource CT Plant to recognize newer, more efficient, turbine technology;
- revise the escalation rate used to annually adjust the Gross CONE estimate in the years between quadrennial reviews; and
- include a 10% cost adder in the method used to estimate net energy revenue offsets, so as to be consistent with the 10% margin sellers are allowed to include in their energy market offers.

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."[6] If, as a result of that review, PJM proposes that the VRR

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3 Tariff, Attachment DD, sections 5.10(a)(i)–(iii).

4 Tariff, Attachment DD, section 5.10(a)(iv).

5 Tariff, Attachment DD, section 5.10(a)(v).

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

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 which the new values would be applied."[7] 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.[8] 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.[9] 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.[10]

PJM retained an independent consultant, The Brattle Group ("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 Fourth Review of PJM's Variable Resource Requirement Curve ("2018 VRR Curve Report");[11] and Brattle and S&L conducted a second study entitled PJM Cost of New Entry—CT and Combined-Cycle ("CC") Plants with June 1, 2022 Online Date ("2018 CONE Study").[12] Based on these analyses, PJM's staff proposed Tariff changes to the VRR Curve shape, the CONE values, and the net EAS revenue offset methodology for implementation in connection with the 2019 BRA for the 2022/2023 Delivery Year.[13]

PJM's recommendations, as well as alternative stakeholder recommendations, were discussed and developed at numerous stakeholder meetings, culminating in

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7 Tariff, Attachment DD, section 5.10(a)(iii)(A).

8 Tariff, Attachment DD, section 5.10(a)(iii)(C).

9 Tariff, Attachment DD, section 5.10(a)(iii)(D). The Commission granted PJM a Tariff waiver to extend this filing deadline to October 12, 2018. *PJM Interconnection, L.L.C.*, 164 FERC ¶ 61,108, at P 12 (2018).

10 Tariff, Attachment DD, sections 5.10(a)(vi)(C)–(D).

11 *See* Attachment G, Affidavit of Samuel A. Newell and David Luke Oates (the 2018 VRR Curve Report is included as Exhibit No. 2 to Attachment G).

12 *See* Attachment E, Affidavit of Samuel A. Newell, John H. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C. ("Brattle/S&L CONE Affidavit") (the 2018 CONE Study is included as Exhibit No. 2 to Attachment E).

13 The Commission granted PJM a Tariff waiver allowing PJM to reschedule the 2019 BRA from May 2019 to August 2019. *PJM Interconnection, L.L.C.*, 164 FERC ¶ 61,153, at P 12 (2018).

meetings of the Markets and Reliability Committee ("MRC") and Members Committee on September 27, 2018. The MRC considered and voted on the PJM staff recommendations and three stakeholder-developed alternatives. While the PJM staff proposal received the most votes in favor, none of the proposals attained majority support at the MRC.[14] The Members Committee adopted the MRC voting results.

In accordance with the Tariff, the PJM Board met to consider the PJM staff recommendations and stakeholder input, and determined to direct PJM staff to file 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 Cost of New Entry ("Net CONE")[15] reflected as $/MW-day (on the price axis) and the target reliability requirement (on the megawatt quantity axis).[16] 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 0.2 percentage points below the approved Installed Reserve Margin ("IRM") (or lower). The current effective Tariff sets that price as 1.5 times the Net CONE.[17]

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14 PJM's proposal received a sector-weighted affirmative vote of 2.32 out of 5. Sector-weighted support for the other three proposals ranged from 1.42 to 2.14 out of 5.

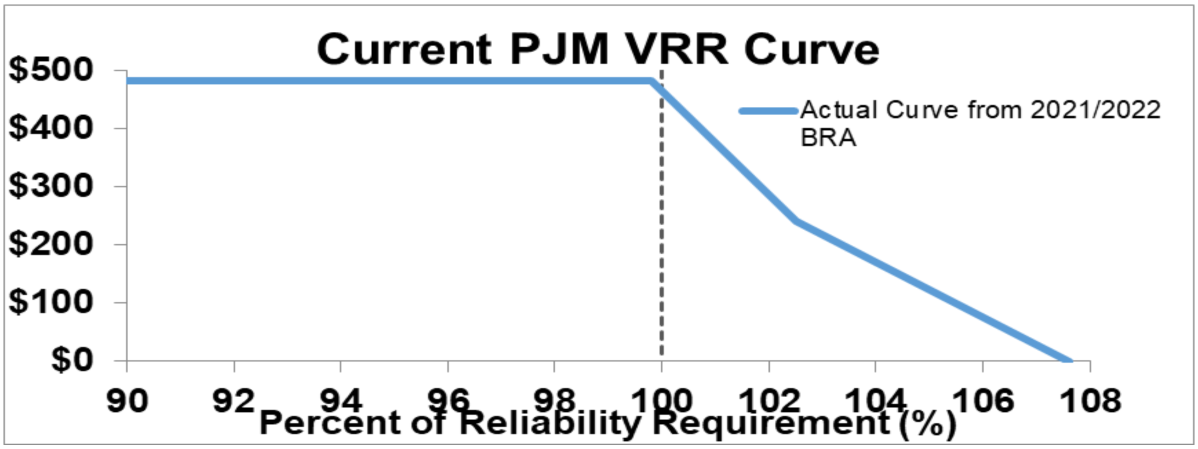
15 Net CONE is calculated by subtracting from CONE (which represents the levelized capital costs and fixed operations and maintenance ("O&M") expenses of a new plant) the net EAS revenues (the net revenues such a plant could be expected to earn in the PJM energy and ancillary services markets). *See* Tariff, section 1 (Definitions-L-M-N).

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

17 To protect against a collapse in demand when the EAS revenue offset is high, the cap is set at Gross CONE if Gross CONE is greater than 1.5 times Net CONE. For simplicity of presentation, this contingency is not depicted in the demand curve graphs included in this transmittal. To be clear, however, this fall-back reliance on Gross CONE under very high EAS conditions will remain an attribute of the VRR Curve under PJM's proposal in this filing.

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 0.2% or more below the IRM target. 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 2.9%. The third segment slopes down more gradually, ending at the point where price equals zero and the cleared capacity exceeds the IRM by 8.8%.

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;[18]
- "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;"[19]
- "render capacity investments less risky, thereby encouraging greater investment and at a lower financing cost;"[20] and

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

19 *Id.* at P 75.

- "reduce the incentive for sellers to withhold capacity in order to exercise market power when aggregate supply is near the Installed Reserve Margin" because "withholding would result in a smaller increase in capacity prices" and thus "would be less profitable."[21]

The Commission has consistently reaffirmed its support for RPM's sloped demand curve, including in its 2014 order on PJM's last periodic VRR Curve review, finding it "appropriate for Annual Resources to face a sloped demand curve and obtain the associated benefits"[22] that the Commission has "seen . . . from the use of a sloped demand curve, such as reduc[ed] price volatility and financing costs."[23]

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."[24] 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."[25]

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20 *Id.*

21 *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 ("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.").

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

23 *Id.*

24 *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.").

25 *ISO New England Inc.*, 147 FERC ¶ 61,173, at P 29 (2014).

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, as shown above, has previously accepted for PJM, NYISO, and ISO New England Inc. ("ISO-NE"). In their comprehensive independent review, Brattle:

- identified the objectives to be served by a VRR Curve (e.g., procuring sufficient resources to maintain resource adequacy, avoiding excessive price volatility, and avoiding susceptibility to market power) to provide the foundation and metrics for an assessment of alternative curve designs;
- 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.[26]

3. Assessment of the Current 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."[27] 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."[28] As applied to VRR Curve analysis, the "random variables" are inputs like

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[26] *See* 2018 VRR Curve Report, Section IV.

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

[28] European Mathematical Society, *Monte-Carlo Method*, Encyclopedia of Mathematics, https://www.encyclopediaofmath.org/index.php/Monte-Carlo_method (last visited Oct. 11, 2018).

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.

Brattle's simulations assume that the average price across all draws will converge at a market-determined Net CONE. This is consistent with the basic design premise of RPM often recognized by the Commission,[29] 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 energy and ancillary services 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.

As a result of its modeling, Brattle found the current VRR Curve achieves the reliability goals for which it was designed. The LOLE is below the 1-in-10 standard; the long-term average IRM is above the target; there are not many individual years where IRM is below the target; and there are relatively few years below the 1 event in 5-year standard.[30] The total annual customer costs were slightly higher for the current VRR Curve than for any of the proposed replacement curves that were evaluated during this review, but all of the annual cost projections were clustered fairly close together, with the total customer cost differences over all curves ranging only a few percent.[31]

4. PJM Proposes to Shift the VRR Curve, to the Left by One Percent, Reflecting Resolution of Certain Supply Uncertainties that Warranted a Conservative One-Percent Rightward Shift in the 2014 RPM Review.

In the 2014 VRR Curve review, PJM largely accepted Brattle's recommendations, but also proposed a shift of the recommended curve 1% to the right, as a conservative approach to address "anticipated changes to PJM's resource base that could not be

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29 *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).

30 2018 VRR Curve Report at 61, Table 9.

31 *Id.* at 66-67, Tables 11, 12.

modeled using historical data."[32] PJM noted several sources of this resource base uncertainty: large scale generation retirements resulting from both the United States Environmental Protection Agency's ("EPA's") Mercury and Air Toxics Standards ("MATS") and fuel pricing changes due to the emergence of low-priced shale gas; heightened competition from the increasing efficiency of gas combined-cycle technology; the D.C. Circuit court's vacatur of Order No. 745;[33] and uncertainty in the manner in which states would implement the EPA's greenhouse gas rule.[34] The Commission accepted this approach, finding that "PJM appropriately accounted for this modeling inadequacy and the underlying potential for supply shifts with a more conservative VRR Curve, i.e., with a VRR Curve that will result in the procurement of additional capacity."[35]

As explained in the attached affidavit of Adam J. Keech, PJM's Executive Director of Market Operations, the reasons for right-shifting the VRR curve that PJM cited in 2014 have been resolved or are much less of a concern:

> The wave of MATS-related retirements is essentially complete; . . . the market has had nearly ten years to react to the emergence of shale gas. . . . [T]he U.S. Supreme Court . . . affirmed the Commission's authority to accept demand resource offers in the capacity market. . . . [and] the greenhouse gas rule has not been implemented.[36]

Even acknowledging the "potential for a significant amount of near-term economic retirements," Mr. Keech points out that the current retirement risk "does not pose the same resource adequacy challenges as the unique confluence of expected events that raised legitimate concerns in 2014 of simultaneous large-scale retirements."[37] PJM also has, since 2014, demonstrated RPM's ability to manage substantial retirements "by attracting new capacity or incentivizing existing capacity to stay online as the market tightens."[38] Accordingly, the 1% rightward shift that was warranted in 2014 as a

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32 *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,183, at P 52 (2014) ("2014 Review Order").

33 *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev'd & remanded*, 136 S. Ct. 760 (2016).

34 2014 Review Order at P 25 (describing PJM's showing).

35 2014 Review Order at P 52.

36 Attachment C, Affidavit of Adam J. Keech ¶ 15 ("Keech Aff.").

37 *Id.*

38 *Id.* (citing *Resource Investment in Competitive Markets*, PJM Interconnection, L.L.C., at 30-34 (May 5, 2016), https://www.pjm.com/~/media/library/reports-

conservative response to an unusual confluence of events is no longer required, and PJM proposes here to reverse that shift.

5. PJM Is Not Changing the Tariff's Current Designation of a Combustion Turbine Plant as the Basis for the CONE Used in the VRR Curve.

As discussed below, PJM proposes to update the turbine technology assumed for the new entry CT plant, which, along with other changes, reduces the Gross CONE in each of the four Tariff-identified CONE Areas by over 20%, compared to the CONE values that would be used in the next BRA absent these proposed changes. PJM does not propose to change in this Section 205 filing, however, the current Tariff requirement that the Reference Resource be a CT plant.

As the Brattle consultants explained in their 2014 review of RPM, "[o]ver the long-term, it should not matter which technology is selected for determining Net CONE as long as the chosen technology is economically viable."[39] In their 2018 VRR Curve Report, Brattle affirms they "continue to believe" that "any technology that is economically viable in the long run could be selected for determining Net CONE."[40] Mr. Keech shows that condition is met here: "CT plants, as a resource category, remain economic options for new entry into the PJM Region."[41] As he notes, the data presented in the 2018 CONE Study to show the large amount of combined cycle plant capacity added to the PJM Region "also shows over 1600 MWs of new combustion turbine plants added to PJM since RPM was adopted."[42] Moreover, two new merchant CT Plants have been added since 2014.[43] Accordingly, "even if not the largest new entry resource category, CT Plants have demonstrated their economic viability in the PJM Region by clearing RPM auctions."[44] While Brattle states only "it is not clear" that CT Plants "will

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notices/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx).

39 2014 Triennial Review Filing of PJM Interconnection, L.L.C., Docket No. ER14-2940-000, Attachment E, 2014 VRR Report at 27 (Sept. 25, 2014).

40 2018 VRR Curve Report at 33 n.42.

41 Keech Aff. ¶ 7.

42 *Id.* (citing 2018 CONE Study at 5, Figure 2).

43 *Id.* (citing 2018 CONE Study at 5 n.17 (addition of 340 MW Doswell Peaking Unit and 141 MW Perryman Unit 6)).

44 *Id.*

remain part of the supply mix in equilibrium,"[45] Mr. Keech emphasizes "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."[46]

As Mr. Keech explains, PJM's choice is well supported. First, CT Plants "represent the cheapest and fastest generation technology that could be brought to the market should market signals indicate the need for new capacity."[47] While acknowledging that a peaking plant should not be the basis for the VRR Curve "if the underlying resource type is uneconomic even with capacity market revenues," where, as in the PJM Region, the "peaking resource class has proven to be viable and economic over many years, . . . it is reasonable, and highly consistent with the purpose of capacity markets, to anchor the VRR Curve with an estimate of the revenues such a peaking resource needs from the capacity market."[48] Mr. Keech notes that CT plants "long have operated well to meet rapid changes in demand, and that essential need will not only continue, but evolve and expand with the changing resource mix."[49] In addition, given that the VRR Curve "has been based on a CT Plant since 2007[, n]ew entry decisions over that time . . . have undoubtedly factored in, to some degree, that stable auction design assumption, . . . [which] provides . . . assurance for the new entry decisions on which resource adequacy depends."[50] Moreover, preserving the same Reference Resource type "also avoids perceived opportunistic switching to units with more favorable economics in any given year."[51]

Second, "there is greater risk of mis-estimating a CC Net CONE than there is of mis-estimating a CT Net CONE" because "[a] CC Plant depends far more on energy market revenues than does a CT Plant and thus a CC Plant is far more susceptible to mis-estimation than a CT Plant in calculating the EAS offset and ultimately the Net CONE."[52] This relative dependence on energy revenues is large, as Brattle's data shows "the reference CC plant would depend on the energy market for about 61% of its revenue requirement, while the reference CT plant would rely on the energy market for only about

45 2018 VRR Curve Report at 33 n.42.

46 Keech Aff. ¶ 7.

47 *Id.* ¶ 8.

48 *Id.*

49 *Id.*

50 *Id.*

51 *Id.*

52 *Id.* ¶ 9.

27% of its revenue requirement."[53] Consequently, a Net CONE based on a CC Plant "is more likely to be inaccurate (compared to actual net new entry costs for the subject plant type) than a CT Net CONE estimate," which "can have a detrimental effect on the VRR Curve's ability to maintain resource adequacy."[54]

Third, Mr. Keech details how Brattle's long-run simulations "lend support to PJM's proposed retention of a CT-based Net CONE, and quantify the reliability risks if RPM was switched to a CC-based Net CONE, and that Net CONE was underestimated."[55] Their simulations cover not only variations on supply and demand, "but also assess the reliability and cost consequences if the Net CONE used for the VRR Curve is underestimated."[56] Brattle's modeling shows that PJM's proposed VRR Curve (curve "B" in their report) "satisfies the 1-in-10 LOLE standard on average under all tested scenarios;"[57] while lowering consumer costs "by $111 million per year, compared to the current VRR Curve."[58]

By contrast, Brattle's proposed CC-based VRR Curve (curve "E" in their report), "fails reliability standards if the CC Net CONE estimate is understated."[59] While Curve E meets reliability standards if it is accurately estimated, if instead it underestimates CC Net CONE by 20%, then that CC-based VRR Curve "would fail the 1-in-10 LOLE standard, resulting in an expected 1.6 loss of load events every ten years."[60] As Mr. Keech points out, "[t]his is not a far-fetched scenario."[61] A CC-based Net CONE that is 20% higher than Brattle's estimate would still be "less than half the Net CONE used in the 2018 BRA."[62] Moreover, "if the true new entry cost instead tracks a CT Net CONE,

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53 *Id.* (citing 2018 VRR Curve Report at vii, Table ES-1).

54 *Id.*

55 *Id.* ¶ 10.

56 *Id.*

57 2018 VRR Curve Report at 66-67, Tables 11 & 12 (Curve "B" row; "Average LOLE" and "Stress" LOLE columns).

58 *Id.*

59 *Id.*

60 2018 VRR Curve Report at 66, Table 11.

61 Keech Aff. ¶ 12.

62 *Id.*

then the Brattle recommended CC-based VRR Curve would perform very poorly, i.e., 3.3 loss of load events every 10 years."[63]

Mr. Keech concludes, the simulations therefore show that "[a] CC Net Cone *might* be reasonable, but it carries greater reliability risk, and that risk arises from the very feature of a CC Net Cone that is most vulnerable, i.e., the inherent uncertainty of a Net CONE calculation that relies to a much greater degree on estimates of energy market revenues."[64]

Ultimately, while preferring a CC-based curve, Brattle acknowledges that they "see an argument that a CT-based curve would more strongly guarantee resource adequacy under all conditions, at a cost that is modest when put in context."[65] Brattle thus observes that "[o]verall, PJM's market-based resource adequacy construct appears to have saved much more than that by attracting and retaining a wide range of resources at competitive market prices well below the estimated cost of new plants."[66]

Finally, both the NYISO and ISO-NE use a CT plant for the Reference Resource in their comparable capacity auctions with downward sloping demand curves. The Commission has accepted those CT-based demand curves for both RTOs in just the last two years.[67] As was the case in *ISO New England Inc.*, the CT-based Net CONE "will 'accommodate the participation of a range of resource types.'"[68] CT plants have been installed since RPM was implemented,[69] and the resource remains a reasonable choice available to developers. The selected VRR Curve should not be designed to limit competition from a plant type available to developers that has all the essential features of a peaking plant that is most reliant on capacity market revenues.

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63 *Id.* (citing 2018 VRR Curve Report at 67, Table 12).

64 *Id.* ¶ 13.

65 2018 VRR Curve Report at 69.

66 *Id.*

67 *ISO New England Inc.*, 161 FERC ¶ 61,035, at PP 36-46 (2017); *N.Y. Indep. Sys. Operator, Inc.*, 158 FERC ¶ 61,028, at PP 27-28, *reh'g denied*, 160 FERC ¶ 61,020 (2017).

68 *ISO New England Inc.*, 161 FERC ¶ 61,035, at P 43 (quoting Motion for Leave to Answer and Answer of ISO New England Inc., Docket No. ER17-795-000, at 9 (Feb. 17, 2017)).

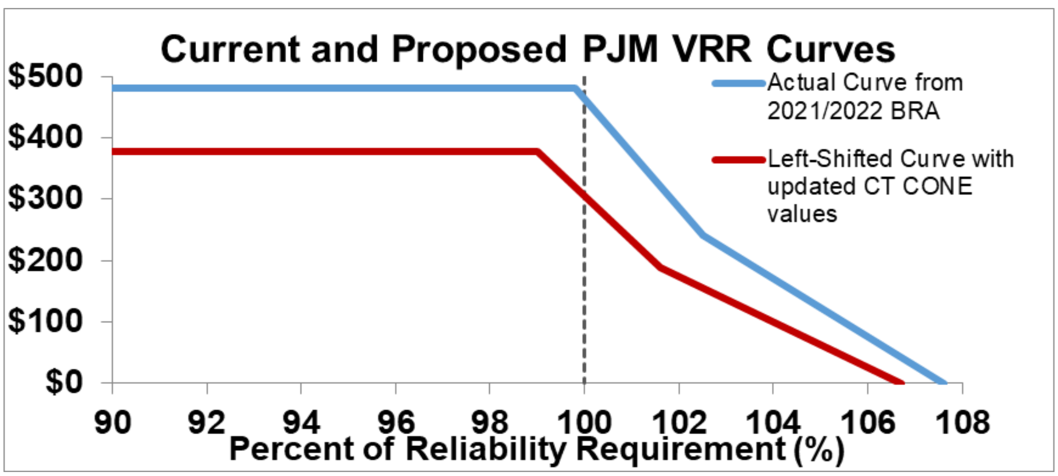
69 *See supra* Section II.B.5.

6. Implementing Tariff Change.

To reflect the proposed VRR Curve in the Tariff, PJM is revising PJM 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 those for the 2022/2023 Delivery Year.[70]

The resulting proposed VRR Curve is shown in Figure 2 below, along with the current VRR Curve for comparison. In addition to the left shift discussed above, the proposed curve reflects the updated, reduced estimates of Gross CONE, as discussed in Section II.C of this transmittal, and an updated Net EAS Revenue offset that reflects both the more efficient H-Frame technology and the introduction of the 10% energy market offer cost adder, discussed in Section II.D.

Figure 2
Proposed and Current VRR Curves



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 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

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[70] 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. PJM is making one clean-up change to those earlier-year descriptions: PJM is dropping references to the Short-Term Resource Procurement Target, which was eliminated as of the 2018/2019 Delivery Year.

currently defines that representative new entry plant, or "Reference Resource," as a CT power plant.[71]

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.[72] 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, 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); and
- CONE Area 4: Western MAAC (PPL, MetEd, Penelec).[73]

The Tariff also includes a mechanism for automatic updates to the CONE values based on changes in the Applicable United States Bureau of Labor Statistics ("BLS") Composite Index, a utility construction cost index.[74] This mechanism is intended to keep

71 Tariff, section 1 (Definitions-R-S).

72 *See, e.g.*, *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, at P 36 (2009) ("March 2009 RPM Order") ("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 . . . .").

73 Tariff, Attachment DD, section 5.10(a)(iv)(A).

74 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 . . . .").

the CONE values up to date with the latest trends in electric plant construction costs in the years between PJM's quadrennial reviews.[75]

For this quadrennial review, PJM followed the same "bottom-up" approach that yielded CONE values previously accepted by the Commission as just and reasonable.[76] In addition to the 2018 VRR Report, Brattle prepared a detailed estimate of the Cost of New Entry for use in the VRR Curve. The results of Brattle's review and analysis are set forth in its 2018 CONE Study. 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. Pfiefenberger 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.[77] Lastly, PJM's Lead Market Strategist, M. Gary Helm, addresses in his affidavit an adjustment to the financial parameters assumed in the Gross CONE estimate, based on the latest financial market data.[78]

2. Proposed Gross CONE Values.

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

Table 1

CONE Area 1:	$108,000/MW-year
CONE Area 2:	$109,700/MW-year
CONE Area 3:	$105,500/MW-year
CONE Area 4:	$105,500/MW-year

PJM is incorporating these proposed values, which are fully supported in the 2018 CONE Report and the accompanying affidavits, in Tariff, Attachment DD, section

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

76 *See* March 2009 RPM Order 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 Inc.*, 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 study conducted by Brattle and S&L).

77 Attachment F, Affidavit of Johannes P. Pfeifenberger and Bin Zhou.

78 Attachment D, Affidavit of M. Gary Helm ("Helm Affidavit").

5.10(a)(iv)(A).[79] In the following sections 3, 4, 5, and 6, PJM highlights and supports several important components of these estimates.

3. Reference Resource.

PJM's current Tariff defines the Reference Resource as a CT power plant "configured with two General Electric ("GE") Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology . . . dual fuel capability, and a heat rate of 10.096 MMbtu/MWh."[80]

PJM proposes to update this definition to reflect the more recent version of GE's Frame CT, i.e., the 7HA turbine, due to project development trends, improved efficiency, and lower costs. Since 2014, over 12,000 MWs of the H- and J-class turbines have been installed, or are under construction, in the PJM Region, although in combined-cycle configurations.[81] Brattle's review of recent orders for GE turbines shows that future CCs are almost exclusively using the H-class turbine.[82] A 7HA-based plant in single-cycle CT configuration also is under construction in ISO-NE, and one such plant was proposed by California Independent System Operator Corp.[83] The 7HA (with a nameplate rating of 320 MW) is larger than the 7FA (nameplate of 190 MW), such that a plant with one 7HA will have capacity not far below the capacity of two 7FAs.[84] The resulting 7HA plant costs on a $/kW basis, as well as the heat rate (9.134 MMbtu/MWh versus 10.096 MMbtu/MWh), are more cost effective and efficient than a 7FA plant, indicating that a 7HA plant is a reasonable choice for the CT Reference Resource in PJM.

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79 In prior CONE change filings, PJM has also updated the CC and CT CONE values used in the Minimum Offer Price Rule ("MOPR") in Section 5.14(h). However, the Commission currently is conducting an FPA section 206 proceeding in Docket No. EL18-178 on PJM's MOPR, which could result in wholesale changes to that provision. Under the circumstances, given the current uncertainty over the scope and application of MOPR, the best course is to address the MOPR CONE values in any compliance filing ordered by the Commission in that case. If such a compliance filing is ordered, and CC and CT values are needed for MOPR, PJM advises that it would update the values in that docket, based on the PJM proposals (or Commission approvals) in this docket.

80 Tariff, section 1 (Definitions-R-S) (defining Reference Resource).

81 2018 CONE Study at 14-15 & Table 6.

82 *Id.* at 14-15.

83 2018 CONE Study at 17.

84 2018 CONE Study at v.

As explained by Mr. Keech,[85] PJM made one further change from Brattle's CONE estimates. Brattle assessed that a CONE Plant located in the Rest-of-RTO area would not install selective catalytic reduction ("SCR") and Carbon Monoxide ("CO") catalyst environmental controls for air emissions, because it would not be compelled by law to do so. Such a plant, however, has an economic incentive in RPM to add these technologies, even if not otherwise required. Otherwise, the plant might face severe run-time restrictions, which could significantly impede the plant's ability to run at peak times, making it more likely to incur performance penalties under PJM's capacity performance rules. PJM therefore asked Brattle to include SCR and CO costs in the CONE estimate for the Rest-of-RTO CONE Area.

To implement this proposed change, PJM is revising Tariff, section 1, definition of Reference Resource to reference one GE Frame 7HA turbine, rather than two Frame 7FA turbines; revising the heat rate to reflect this plant configuration; and eliminating the reference to inlet air chilling. Brattle and S&L explained during the stakeholder process that most plants use evaporative cooling rather than inlet chilling, and the costs and benefits of inlet air chilling have not proven attractive to developers, particularly in light of the ambient conditions in the PJM Region.

4. After-Tax Weighted Average Cost of Capital.

The after-tax weighted average cost of capital or 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. In that respect, Brattle followed essentially the same approach used for the last CONE review, which the Commission found to be "transparent," with "well-supported" assumptions, and resulting in "a reasonable Cost of Capital that 'captures financial market conditions and appropriately balances investor and consumer interests.'"[86]

As Mr. Pfiefenberger 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 ("M&A") transactions. In early 2018, Brattle analyzed the effects of the major federal corporate tax reform adopted at the end of 2017, resulting in an increase in the ATWACC estimate. In August 2018, Brattle revisited its ATWACC estimate, and identified increases in the U.S. risk-free rate and the cost of debt since their early 2018 analysis, resulting in a further increase in ATWACC

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85 Keech Aff. ¶ 20.

86 2014 Review Order at P 76 (quoting Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER17-2940-000, Attachment B at 5 (Nov. 6, 2014)).

("August 21 Supplement"). As shown by Mr. Pfiefenberger and Dr. Zhou, Brattle's August 2018 ATWACC estimate was 8.0%, including debt and % equity ratios of 55% and 45%, respectively, a cost of BB-rated debt of 5.5%, and a cost of equity of 13.0%.

As explained by Mr. Helm, PJM has further updated this analysis with the latest debt costs. He finds that "a merchant generator of the type that would sponsor a new entry plant would likely have a credit rating somewhere between B and BB, rather than being rated BB alone."[87] This reflects the credit ratings of the merchant generators Brattle analyzed from when they were stand-alone companies and "those credit ratings are still a reasonable representation of the credit ratings of entities that may finance new power plants."[88] With credit ratings reflecting a mix of B and BB ratings, "a 6% cost of debt is appropriate."[89] Incorporating that debt cost in the ATWACC formula, the resulting ATWACC is 8.2%.[90]

Commenting on this PJM adjustment in their affidavit, Mr. Pfiefenberger and Dr. Zhou observe that "[w]hile above our estimate, PJM's 8.2% ATWACC recommendation is within the range of available market evidence for merchant generation," including their assessment that "adjust[ing] for the tax law changes and recent interest rate increases, the highest two discount rates (ATWACC) used by financial advisors in recent M&A transactions would increase by about 1% to above 8.3%."[91]

The Gross CONE values set forth in the revised Tariff reflect this estimated ATWAAC of 8.2%.

5. Proper Treatment of Production-Related Operation and Maintenance Costs.

The Gross CONE values proposed in this filing assume that certain major maintenance costs are recovered as Variable O&M through energy market offers. This approach anticipates a forthcoming filing by PJM (within the next few weeks) to make clear that energy market offers for CT plants may include such costs as Variable O&M. The operating costs at issue are expenses related to consumable materials used during plant operations. The maintenance costs at issue are expenses a Market Participant incurs as a result of electric production including, for example, periodic turbine inspection and repair that is highly dependent on how often the unit is run. PJM's rules currently can be

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87 Helm Affidavit ¶ 9.

88 *Id.*

89 *Id.*

90 *Id.*

91 Attachment F ¶ 8.

read to prohibit CTs and CCs, but not other resource types, from including these costs in their energy market offers. To remedy this issue, PJM intends to seek Commission approval to allow Market Participants to recover these usage-driven O&M costs through their cost-based offers in the PJM energy market.

For purposes of the present filing, in recognition that these costs are variable and should be recovered through energy market offers, these costs should not be embedded in the capacity market auction parameters. Accordingly, the Gross CONE values supported by Brattle and included in this filing (as listed above in Section II.C.2) *do not* include these usage-driven operation and maintenance costs.

If the Commission disagrees with this change, either through an order on this filing or an order on the section 206 filing, PJM commits to submitting a compliance filing in this proceeding with Gross CONE values that assume recovery of the subject operations and maintenance costs in the capacity market. PJM and Brattle developed alternative Gross CONE values during the stakeholder process that include these O&M costs, and shared them with stakeholders. To further put parties on notice of the impact of the Commission's ultimate decision on this issue, PJM states here the Gross CONE values for each CONE Area, which incorporate these O&M costs:

Table 2

CONE Area 1: $126,700/MW-year
CONE Area 2: $128,200/MW-year
CONE Area 3: $124,500/MW-year
CONE Area 4: $124,700/MW-year

In addition, the Tariff also states an estimated value for Variable O&M to be used in determining the EAS Offset. As explained in the Brattle/S&L CONE Affidavit, they estimated the variable O&M value "to be $6.93 per MWh, based on $5.83/MWh for major maintenance and $1.10/MWh for consumables, waste disposal and other variable O&M."[92] This value results from "convert[ing] the starts-based major maintenance costs reported in the 2018 CONE Study to an hours-based value based on major maintenance costs of $23,464/start, an average runtime of 11.1 hours per start, and average capacity of 366 MW across CONE Areas."[93] By this filing, PJM proposes to revise the Variable O&M value stated in Tariff, Attachment DD, section 5.10(a)(v)(A), to reflect this updated estimate. Alternatively, "if those major maintenance costs are *not* included in energy market offers and the CONE values . . . above are instead adopted, . . . the Variable O&M of the reference CT plant [should] be $1.10 per MWh."[94]

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92 Brattle/S&L CONE Affidavit ¶ 22.

93 *Id.*

94 *Id.*

6. State Sales Tax Exemption for Certain Plant Equipment.

Brattle's early 2018 CONE estimate assumed that new entry plant developers would need to pay sales tax in each of the four states where the Reference Resource is assumed to be installed (i.e., New Jersey, Pennslyvania, Maryland, and Ohio), but stakeholder input and Brattle's further research revealed that equipment and materials are exempt from state sales tax.[95] The proposed Gross CONE values, for all CONE Areas, therefore remove sales tax on equipment and materials.

7. 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, weights cost indices published by the U. S. Department of Commerce's Bureau of Labor Statistics for labor (20%), turbines (30%), and materials (50%). In the 2014 Review Order, the Commission "agree[d] with PJM that this proposed [Tariff] revision will allow for the annual adjustments to CONE values to better reflect changes in applicable industry costs, and is just and reasonable."[96]

PJM proposes to continue to rely on these same three cost indices, but to change their weightings slightly to better accord with the new Gross CONE estimate of CT plant capital costs. As shown in the Brattle CONE Report, the estimated capital costs for the CT plant entering service in 2022 break down as approximately 22% labor, 26% turbines, and 52% materials. Accordingly, to escalate that plant cost estimate for the subsequent three years, PJM proposes to weight the indices as 20% labor, 25% turbines, and 55% materials. This change is shown as a revision to the weighting values stated in Tariff, Attachment DD, section 5.10(a)(iv)(B).

Once that escalation is applied, a further annual adjustment is needed, beginning with the 2023/2024 Delivery Year. The tax law passed in December 2017 temporarily increased bonus depreciation to 100%, but then begins to phase it down.[97] Bonus depreciation is a form of highly accelerated tax depreciation immediately upon in-service of a depreciable asset. Per the 2017 tax law, bonus depreciation is allowed for companies not classified as public utilities up to 100% of tax basis. This reduces the Gross CONE for a merchant new entry plant entering service in June 1, 2022, as assumed in the 2018 CONE Study. That reduction is reflected in the CONE values proposed here. New entry

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95 As Brattle reported in their September 27, 2018 update memo, the states of New Jersey, Pennsylvania, Maryland, and Ohio are exempt from sales tax for equipment and materials used in the production of electricity.

96 2014 Review Order at P 115.

97 *See* Internal Revenue Code section 168(k)(6).

plants in subsequent years, however, will have progressively less favorable tax treatment as the 100% bonus depreciation phases down by 20% each year. The 2018 CONE Report calculates that this known, enacted change will increase CONE each year for a new CT plant by 2.2% as the bonus depreciation phases down, and recommends an annual adjustment to account for this change. Accordingly, PJM is further revising Tariff, Attachment DD, section 5.10(a)(iv)(B) to apply a 1.022 gross-up factor to CONE each year to account for the declining tax advantages as bonus depreciation phases out.[98]

D. Energy and Ancillary Services Methodology.

1. Background.

The Tariff directs PJM to estimate the energy revenues that the Reference Resource would have received based on actual Locational Marginal Pricing 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.[99] The Tariff directs PJM to then add ancillary service revenues of $2,199 per MW-year.[100]

PJM carefully considered a number of changes to the EAS methodology during the Tariff-prescribed analysis and stakeholder process. Based on the information, analysis, and stakeholder input gathered in that process, the PJM Board chose to make no changes to the EAS rules in the Tariff, with the single exception of the 10% adder discussed in the following subsection.

2. Incorporation of Ten Percent Cost Margin into the Peak-Hour Dispatch Methodology.

The current EAS method estimates energy revenues in part based on fuel costs. However, the EAS rules do not presently recognize the 10% margin that the energy market rules allow to be included in the cost-based energy market offers of actual generation resources.[101] Inasmuch as this adder is intended to account for uncertainties in the determination of these energy market participation costs, the 10% adder should likewise be incorporated into the cost-based energy market offer assumed for the

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98 PJM also is making a clean-up change to Tariff, Attachment DD, section 5.10, by removing several outdated references to the Short Term Resource Procurement Target, which was eliminated by order of the Commission and has not been in effect for many years.

99 Tariff, Attachment DD, section 5.10(a)(v)(A).

100 Tariff, Attachment DD, section 5.10(a)(v)(A).

101 Operating Agreement, Schedule 1, section 6.4.2.

Reference Resource in the EAS estimating method's Peak-Hour Dispatch rules. These same uncertainties, e.g., assumptions regarding the applicable gas index hub, Day-ahead versus intra-day gas arrangements, and assigned Locational Marginal Pricing, would confront the Reference Resource if it were preparing an energy market offer.[102]

Therefore, it is reasonable and consistent with the approved energy market rules to apply the 10% margin to the cost-based energy market offer of the Reference Resource. Introduction of the 10% margin into the Peak-Hour Dispatch of the Reference Resource provides an offset around these uncertainties and also accounts for differences between the key assumptions made for the Reference Resource relative to actual attributes of a similarly-situated representative resource. Accordingly, PJM is adding to the definition of Peak-Hour Dispatch in Tariff, Attachment DD, section 1 a reference to and description of the 10% adder.

E. All Changes Proposed in this Filing Are to Be Effective Starting With the 2022/2023 Delivery Year and Will Not Disturb the 2019/2020, 2020/2021, and 2021/2022 Delivery Years.

PJM is proposing to implement all the changes proposed in this filing starting with the 2022/2023 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 2021/2022 Delivery Year, and will govern issues related to Delivery Years prior to the 2022/2023 Delivery Year, including any Incremental Auctions conducted for Delivery Years prior to the 2022/2023 Delivery Year. Thus, the VRR Curves, Gross CONE values, net EAS revenue offsets, Net CONEs, and all other inputs and parameters determined for the 2019/2020, 2020/2021, and 2021/2022 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 2022/2023 Delivery Year and all subsequent Delivery Years.[103]

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102 As Brattle observed on a closely related point, 2018 VRR Curve Report at 23:

> 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.

103 *See, e.g.*, proposed Tariff, Attachment DD, section 5.10(a)(i) ("For the 2018/2019 Delivery Year and subsequent Delivery Years . . . the Variable Resource

III. EFFECTIVE DATE

As explained above, PJM requests an effective date of December 12, 2018.

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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Requirement Curve for the PJM Region shall be . . . ."); *id.*, Attachment DD, section 5.10(a)(ii)(C) ("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."); *id.*, Attachment DD, section 5.10(a)(iv)(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 Delivery Year and LDA.").

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 Adam J. Keech on Behalf of PJM Interconnection, L.L.C. Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, as Attachment C (including Capacity Factor Trends as Exhibit No. 1);

4. Affidavit of M. Gary Helm on Behalf of PJM Interconnection, L.L.C. Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, as Attachment D;

5. Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang on Behalf of PJM Interconnection, L.L.C., as Attachment E (including Qualifications as Exhibit No. 1, 2018 CONE Study as Exhibit No. 2, and September 26, 2018 Memo as Exhibit No. 3);

6. Affidavit of Johannes P. Pfeifenberger and Bin Zhou on Behalf of PJM Interconnection, L.L.C., as Attachment F (including Qualifications as Exhibit No. 1 and August 21 Supplement as Exhibit No. 2); and

7. Affidavit of Samuel A. Newell and David Luke Oates on Behalf of PJM Interconnection, L.L.C. Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, as Attachment G (including Qualifications as Exhibit No. 1 and 2018 VRR Curve Report as Exhibit No. 2).

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,[104] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.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

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

members and all state utility regulatory commissions in the PJM Region[105] 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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[105] 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 March 15, 2019.

Respectfully submitted,

/s/ Paul M. Flynn

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October 12, 2018

Attachment A

PJM Open Access Transmission Tariff

(Marked / Redline Format)

Definitions – O – P - Q

Obligation:

"Obligation" shall mean all amounts owed to PJMSettlement for purchases from the PJM Markets, Transmission Service, (under both Tariff, Part II and Part III), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJMSettlement in the future for capacity purchases within the PJM capacity markets will be added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Offer Data:

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the Transmission System in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

Office of the Interconnection:

"Office of the Interconnection" shall mean the employees and agents of PJM Interconnection, L.L.C. subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Office of the Interconnection Control Center:

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

On-Site Generators:

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-Time Information System:

"Open Access Same-Time Information System," "PJM Open Access Same-Time Information System" or "OASIS" shall mean the electronic communication and information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C., on file with the Commission.

Operating Day:

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

Operating Margin:

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

Operating Margin Customer:

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

Operationally Deliverable:

"Operationally Deliverable" shall mean, as determined by the Office of the Interconnection, that there are no operational conditions, arrangements or limitations experienced or required that threaten, impair or degrade effectuation or maintenance of deliverability of capacity or energy from the external Generation Capacity Resource to loads in the PJM Region in a manner comparable to the deliverability of capacity or energy to such loads from Generation Capacity Resources located inside the metered boundaries of the PJM Region, including, without limitation, an identified need by an external Balancing Authority Area for a remedial action scheme or manual generation trip protocol, transmission facility switching arrangements that would have the effect of radializing load, or excessive or unacceptable frequency of regional reliability limit violations or (outside an interregional agreed congestion management process) of local reliability dispatch instructions and commitments.

Opportunity Cost:

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

OPSI Advisory Committee:

"OPSI Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.G.

Option to Build:

"Option to Build" shall mean the option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

Optional Interconnection Study:

"Optional Interconnection Study" shall mean a sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement:

"Optional Interconnection Study Agreement" shall mean the form of agreement for preparation of an Optional Interconnection Study, as set forth in Tariff, Attachment N-3.

Part I:

"Part I" shall mean the Tariff Definitions and Common Service Provisions contained in Tariff, Part I, sections 1 through 12A.

Part II:

"Part II" shall mean Tariff, sections 13 through 27A pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part III:

"Part III" shall mean Tariff, sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part IV:

"Part IV" shall mean Tariff, sections 36 through 112C pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part V:

"Part V" shall mean Tariff, sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part VI:

"Part VI" shall mean Tariff, sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Participant:

"Participant" shall mean a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer**.**

Parties:

"Parties" shall mean the Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

Peak-Hour Dispatch:

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under Tariff, Attachment DD, section 5, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle), plus 10% of such costs, for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time

LMP is greater than or equal to the cost to generate, plus 10% of such costs, under the same conditions as described above for the Day-Ahead Energy Market.

Peak Market Activity:
"Peak Market Activity" shall mean a measure of exposure for which credit is required, involving peak exposures in rolling three-week periods over a year timeframe, with two semi-annual reset points, pursuant to provisions of Tariff, Attachment Q, section V.A. Peak Market Activity shall exclude FTR Net Activity, Virtual Transactions Net Activity, and Export Transactions Net Activity.

Peak Season:

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

Percentage Internal Resources Required:

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

Performance Assessment Interval:

"Performance Assessment Interval" shall mean each Real-time Settlement Interval for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Intervals for a Base Capacity Resource shall not include any intervals outside the calendar months of June through September.

PJM:

"PJM" shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Administrative Service:

"PJM Administrative Service" shall mean the services provided by PJM pursuant to Tariff, Schedule 9.

PJM Board:

"PJM Board" shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

"PJM Control Area" shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Entities:

"PJM Entities" shall mean PJM, including the Market Monitoring Unit, the PJM Board, and PJM's officers, employees, representatives, advisors, contractors, and consultants.

PJM Interchange:

"PJM Interchange" shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds, or is exceeded by, the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller; or (e) the interval scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the inteval scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Interchange Energy Market:

"PJM Interchange Energy Market" shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related servicesestablished pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K – Appendix.

PJM Interchange Export:

"PJM Interchange Export" shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load is exceeded by the sum of the inteval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller.

PJM Interchange Import:

"PJM Interchange Import" shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the interval scheduled deliveries of

Spot Market Energy to an External Market Buyer; or (d) the interval scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Liaison:

"PJM Liaison" shall mean the liaison established under Tariff, Attachment M, section III.I.

PJM Management:

"PJM Management" shall mean the officers, executives, supervisors and employee managers of PJM.

PJM Manuals:

"PJM Manuals" shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Markets:

"PJM Markets" shall mean the PJM Interchange Energy and capacity markets, including the RPM auctions, together with all bilateral or other wholesale electric power and energy transactions, capacity transactions, ancillary services transactions (including black start service), transmission transactions and any other market operated under the PJM Tariff or Operating Agreement within the PJM Region, wherein Market Participants may incur Obligations to PJMSettlement.

PJM Market Rules:

"PJM Market Rules" shall mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.

PJM Net Assets:

"PJM Net Assets**"** shall mean the total assets per PJM's consolidated quarterly or year-end financial statements most recently issued as of the date of the receipt of written notice of a claim less amounts for which PJM is acting as a temporary custodian on behalf of its Members, transmission developers/Designated Entities, and generation developers, including, but not limited to, cash deposits related to credit requirement compliance, study and/or interconnection receivables, member prepayments, invoiced amounts collected from Net Buyers but have not yet been paid to Net Sellers, and excess congestion (as described in Operating Agreement, Schedule 1, section 5.2.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.6).

PJM Region:

"PJM Region" shall have the meaning specified in the Operating Agreement.

PJM Regional Practices Document:
"PJM Regional Practices Document" shall mean the document of that title that compiles and describes the practices in the PJM Markets and that is made available in hard copy and on the Internet.

PJM Region Installed Reserve Margin:

"PJM Region Installed Reserve Margin" shall mean the percent installed reserve margin for the PJM Region required pursuant to RAA, Schedule 4.1, as approved by the PJM Board.

PJM Region Peak Load Forecast:

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in Tariff, Attachment DD, section 5.

PJM Region Reliability Requirement:

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

PJMSettlement:

"PJM Settlement" or "PJM Settlement, Inc." shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operaitng Agreement, section 3.3.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

"PJM Tariff," "Tariff," "O.A.T.T.," "OATT," or "PJM Open Access Transmission Tariff" shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Plan:

"Plan" shall mean the PJM market monitoring plan set forth in Tariff, Attachment M.

Planned Demand Resource:

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Planned External Financed Generation Capacity Resource:

"Planned External Financed Generation Capacity Resource" shall mean a Planned External Generation Capacity Resource that, prior to August 7, 2015, has an effective agreement that is the equivalent of an Interconnection Service Agreement, has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close, and has secured at least 50 percent of the MWs of firm transmission service required to qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

Planned External Generation Capacity Resource:

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Planned Financed Generation Capacity Resource:

"Planned Financed Generation Capacity Resource" shall mean a Planned Generation Capacity Resource that, prior to August 7, 2015, has an effective Interconnection Service Agreement and has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close.

Planned Generation Capacity Resource:

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Planning Period:

"Planning Period" shall mean the 12 moths beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Planning Period Balance:

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

Planning Period Quarter:

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

Point(s) of Delivery:

“Point(s) of Delivery” shall mean the point(s) on the Transmission Provider’s Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Tariff, Part II. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point of Interconnection:

“Point of Interconnection” shall mean the point or points where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

Point(s) of Receipt:

“Point(s) of Receipt” shall mean point(s) of interconnection on the Transmission Provider’s Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Tariff, Part II. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point-To-Point Transmission Service:

“Point-To-Point Transmission Service shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Tariff, Part II.

Power Purchaser:

“Power Purchaser” shall mean the entity that is purchasing the capacity and energy to be transmitted under the Tariff.

PRD Curve:

“PRD Curve” shall have the meaning provided in the Reliability Assurance Agreement.

PRD Provider:

“PRD Provider” shall have the meaning provided in the Reliability Assurance Agreement.

PRD Reservation Price:

“PRD Reservation” Price shall have the meaning provided in the Reliability Assurance Agreement.

PRD Substation:

“PRD Substation” shall have the meaning provided in the Reliability Assurance Agreement.

Pre-Confirmed Application:

"Pre-Confirmed Application" shall be an Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

Pre-Emergency Load Response Program:

"Pre-Emergency Load Response Program" shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Pre-Expansion PJM Zones:

"Pre-Expansion PJM Zones" shall be zones included in the Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC ("MAIT") (MAIT owns and operates the transmission facilities in the Metropolitan Edison Company Zone and the Pennsylvania Electric Company Zone), PECO Energy Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

Price Responsive Demand:

"Price Responsive Demand" shall have the meaning provided in the Reliability Assurance Agreement.

Primary Reserve:

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

Primary Reserve Alert

"Primary Reserve Alert" shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

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

Prior CIL Exception External Resource:

"Prior CIL Exception External Resource" shall mean an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in RAA, Article I or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided in the definition of Capacity Import Limit. In the event only a portion (in MW) of an external Generation Capacity Resource has a Pseudo-Tie into the PJM Region, that portion of the external Generation Capacity Resource , which can include up to the maximum megawatt amount cleared in any prior RPM auction or committed in an FRR Capacity Plan (and no other portion thereof) is eligible for treatment as a Prior CIL Exception External Resource if such portion satisfies the requirements of the first sentence of this definition.

Project Financing:

"Project Financing" shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer's obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

Project Finance Entity:

"Project Finance Entity" shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer's obligations under the corresponding power purchase agreement.

Projected PJM Market Revenues:

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Proportional Multi-Driver Project:

"Proportional Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Pseudo-Tie:

"Pseudo-Tie" shall have the same meaning provided in the Operating Agreement.

Public Policy Objectives:

"Public Policy Objectives" shall have the same meaning provided in the Operating Agreement.

Public Policy Requirements:

"Public Policy Requirements" shall have the same meaning provided in the Operating Agreement.

Qualifying Transmission Upgrade:

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

Queue Position:

"Queue Position" shall mean the priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Tariff, Part VI.

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 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:

“Reference Resource” shall mean a combustion turbine generating station, configured with a single~~two~~ General Electric Frame ~~7FA~~ 7HA turbine~~s~~ with ~~inlet air cooling to 50 degrees~~evaporative cooling, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of ~~10.096~~9.134 Mmbtu/ MWh.

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 seperately 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 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.

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.

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 for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource or a Capacity Storage Resource; or (v) used in association with restoration or black start service.

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.

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 Demand 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 Demand 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.

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%)]~~ minus the Short-Term Resource Procurement Target~~;

  - 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%)]~~ minus the Short-Term Resource Procurement Target~~; 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%)]~~ minus the Short-Term Resource Procurement Target~~.

- For the 2022/2023 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 [1.5 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%)].

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 ~~2015~~2019/~~2016~~2020, ~~2016~~2020/~~2017~~2021, and ~~2017~~2021/~~2018~~ 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 Delivery Year and LDA. For the Delivery Year commencing on June 1, ~~2018~~2022, and continuing thereafter unless and until changed pursuant to subsection (B) below, 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")	~~132,200~~108,000
BGE, PEPCO ("CONE Area 2")	~~130,300~~109,700
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC ("CONE Area 3")	~~128,900~~105,500
PPL, MetEd, Penelec ("CONE Area 4")	~~130,300~~105,500

B) Beginning with the ~~2019~~2023/~~2020~~ 2024 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 ~~50~~55%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted ~~30~~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 ~~2018~~2022/~~2019~~ 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.

v) Net Energy and Ancillary Services Revenue Offset

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.~~47~~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) ~~For the Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the Office of the Interconnection will employ for purposes of the Variable Resourcce Requirement Curves for such Delivery Years the same calculations of the sub-regional Net Energy and Ancillary Services Revenue Offsets that were used in the Base Residual Auctions for such Delivery year and sub-region. For the 2018/2019 Delivery Year and subsequent Delivery Years, t~~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.

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 PJM 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) of this Attachment DD 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) of this Attachment DD 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) of this Attachment DD 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

PJM Open Access Transmission Tariff

(Clean Format)

Definitions – O – P - Q

Obligation:

"Obligation" shall mean all amounts owed to PJMSettlement for purchases from the PJM Markets, Transmission Service, (under both Tariff, Part II and Part III), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJMSettlement in the future for capacity purchases within the PJM capacity markets will be added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Offer Data:

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the Transmission System in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

Office of the Interconnection:

"Office of the Interconnection" shall mean the employees and agents of PJM Interconnection, L.L.C. subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Office of the Interconnection Control Center:

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

On-Site Generators:

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-Time Information System:

"Open Access Same-Time Information System," "PJM Open Access Same-Time Information System" or "OASIS" shall mean the electronic communication and information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C., on file with the Commission.

Operating Day:

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

Operating Margin:

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

Operating Margin Customer:

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

Operationally Deliverable:

"Operationally Deliverable" shall mean, as determined by the Office of the Interconnection, that there are no operational conditions, arrangements or limitations experienced or required that threaten, impair or degrade effectuation or maintenance of deliverability of capacity or energy from the external Generation Capacity Resource to loads in the PJM Region in a manner comparable to the deliverability of capacity or energy to such loads from Generation Capacity Resources located inside the metered boundaries of the PJM Region, including, without limitation, an identified need by an external Balancing Authority Area for a remedial action scheme or manual generation trip protocol, transmission facility switching arrangements that would have the effect of radializing load, or excessive or unacceptable frequency of regional reliability limit violations or (outside an interregional agreed congestion management process) of local reliability dispatch instructions and commitments.

Opportunity Cost:

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

OPSI Advisory Committee:

"OPSI Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.G.

Option to Build:

"Option to Build" shall mean the option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

Optional Interconnection Study:

"Optional Interconnection Study" shall mean a sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement:

"Optional Interconnection Study Agreement" shall mean the form of agreement for preparation of an Optional Interconnection Study, as set forth in Tariff, Attachment N-3.

Part I:

"Part I" shall mean the Tariff Definitions and Common Service Provisions contained in Tariff, Part I, sections 1 through 12A.

Part II:

"Part II" shall mean Tariff, sections 13 through 27A pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part III:

"Part III" shall mean Tariff, sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part IV:

"Part IV" shall mean Tariff, sections 36 through 112C pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part V:

"Part V" shall mean Tariff, sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part VI:

"Part VI" shall mean Tariff, sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Participant:

"Participant" shall mean a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer**.**

Parties:

"Parties" shall mean the Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

Peak-Hour Dispatch:

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under Tariff, Attachment DD, section 5, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle), plus 10% of such costs, for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time

LMP is greater than or equal to the cost to generate, plus 10% of such costs, under the same conditions as described above for the Day-Ahead Energy Market.

Peak Market Activity:
"Peak Market Activity" shall mean a measure of exposure for which credit is required, involving peak exposures in rolling three-week periods over a year timeframe, with two semi-annual reset points, pursuant to provisions of Tariff, Attachment Q, section V.A. Peak Market Activity shall exclude FTR Net Activity, Virtual Transactions Net Activity, and Export Transactions Net Activity.

Peak Season:

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

Percentage Internal Resources Required:

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

Performance Assessment Interval:

"Performance Assessment Interval" shall mean each Real-time Settlement Interval for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Intervals for a Base Capacity Resource shall not include any intervals outside the calendar months of June through September.

PJM:

"PJM" shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Administrative Service:

"PJM Administrative Service" shall mean the services provided by PJM pursuant to Tariff, Schedule 9.

PJM Board:

"PJM Board" shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

“PJM Control Area” shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Entities:

“PJM Entities” shall mean PJM, including the Market Monitoring Unit, the PJM Board, and PJM’s officers, employees, representatives, advisors, contractors, and consultants.

PJM Interchange:

“PJM Interchange” shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds, or is exceeded by, the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller; or (e) the interval scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the inteval scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Interchange Energy Market:

“PJM Interchange Energy Market” shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related servicesestablished pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K – Appendix.

PJM Interchange Export:

“PJM Interchange Export” shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load is exceeded by the sum of the inteval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller.

PJM Interchange Import:

“PJM Interchange Import” shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the interval scheduled deliveries of

Spot Market Energy to an External Market Buyer; or (d) the interval scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Liaison:

"PJM Liaison" shall mean the liaison established under Tariff, Attachment M, section III.I.

PJM Management:

"PJM Management" shall mean the officers, executives, supervisors and employee managers of PJM.

PJM Manuals:

"PJM Manuals" shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Markets:

"PJM Markets" shall mean the PJM Interchange Energy and capacity markets, including the RPM auctions, together with all bilateral or other wholesale electric power and energy transactions, capacity transactions, ancillary services transactions (including black start service), transmission transactions and any other market operated under the PJM Tariff or Operating Agreement within the PJM Region, wherein Market Participants may incur Obligations to PJMSettlement.

PJM Market Rules:

"PJM Market Rules" shall mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.

PJM Net Assets:

"PJM Net Assets**"** shall mean the total assets per PJM's consolidated quarterly or year-end financial statements most recently issued as of the date of the receipt of written notice of a claim less amounts for which PJM is acting as a temporary custodian on behalf of its Members, transmission developers/Designated Entities, and generation developers, including, but not limited to, cash deposits related to credit requirement compliance, study and/or interconnection receivables, member prepayments, invoiced amounts collected from Net Buyers but have not yet been paid to Net Sellers, and excess congestion (as described in Operating Agreement, Schedule 1, section 5.2.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.6).

PJM Region:

"PJM Region" shall have the meaning specified in the Operating Agreement.

PJM Regional Practices Document:
"PJM Regional Practices Document" shall mean the document of that title that compiles and describes the practices in the PJM Markets and that is made available in hard copy and on the Internet.

PJM Region Installed Reserve Margin:

"PJM Region Installed Reserve Margin" shall mean the percent installed reserve margin for the PJM Region required pursuant to RAA, Schedule 4.1, as approved by the PJM Board.

PJM Region Peak Load Forecast:

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in Tariff, Attachment DD, section 5.

PJM Region Reliability Requirement:

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

PJMSettlement:

"PJM Settlement" or "PJM Settlement, Inc." shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operaitng Agreement, section 3.3.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

"PJM Tariff," "Tariff," "O.A.T.T.," "OATT," or "PJM Open Access Transmission Tariff" shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Plan:

"Plan" shall mean the PJM market monitoring plan set forth in Tariff, Attachment M.

Planned Demand Resource:

“Planned Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Planned External Financed Generation Capacity Resource:

“Planned External Financed Generation Capacity Resource” shall mean a Planned External Generation Capacity Resource that, prior to August 7, 2015, has an effective agreement that is the equivalent of an Interconnection Service Agreement, has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close, and has secured at least 50 percent of the MWs of firm transmission service required to qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

Planned External Generation Capacity Resource:

“Planned External Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Planned Financed Generation Capacity Resource:

“Planned Financed Generation Capacity Resource” shall mean a Planned Generation Capacity Resource that, prior to August 7, 2015, has an effective Interconnection Service Agreement and has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close.

Planned Generation Capacity Resource:

“Planned Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Planning Period:

“Planning Period” shall mean the 12 moths beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Planning Period Balance:

“Planning Period Balance” shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

Planning Period Quarter:

“Planning Period Quarter” shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

Point(s) of Delivery:

“Point(s) of Delivery” shall mean the point(s) on the Transmission Provider’s Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Tariff, Part II. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point of Interconnection:

“Point of Interconnection” shall mean the point or points where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

Point(s) of Receipt:

“Point(s) of Receipt” shall mean point(s) of interconnection on the Transmission Provider’s Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Tariff, Part II. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point-To-Point Transmission Service:

“Point-To-Point Transmission Service shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Tariff, Part II.

Power Purchaser:

“Power Purchaser” shall mean the entity that is purchasing the capacity and energy to be transmitted under the Tariff.

PRD Curve:

“PRD Curve” shall have the meaning provided in the Reliability Assurance Agreement.

PRD Provider:

“PRD Provider” shall have the meaning provided in the Reliability Assurance Agreement.

PRD Reservation Price:

“PRD Reservation” Price shall have the meaning provided in the Reliability Assurance Agreement.

PRD Substation:

“PRD Substation” shall have the meaning provided in the Reliability Assurance Agreement.

Pre-Confirmed Application:

"Pre-Confirmed Application" shall be an Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

Pre-Emergency Load Response Program:

"Pre-Emergency Load Response Program" shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Pre-Expansion PJM Zones:

"Pre-Expansion PJM Zones" shall be zones included in the Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC ("MAIT") (MAIT owns and operates the transmission facilities in the Metropolitan Edison Company Zone and the Pennsylvania Electric Company Zone), PECO Energy Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

Price Responsive Demand:

"Price Responsive Demand" shall have the meaning provided in the Reliability Assurance Agreement.

Primary Reserve:

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

Primary Reserve Alert

"Primary Reserve Alert" shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

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

Prior CIL Exception External Resource:

"Prior CIL Exception External Resource" shall mean an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in RAA, Article I or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided in the definition of Capacity Import Limit. In the event only a portion (in MW) of an external Generation Capacity Resource has a Pseudo-Tie into the PJM Region, that portion of the external Generation Capacity Resource , which can include up to the maximum megawatt amount cleared in any prior RPM auction or committed in an FRR Capacity Plan (and no other portion thereof) is eligible for treatment as a Prior CIL Exception External Resource if such portion satisfies the requirements of the first sentence of this definition.

Project Financing:

"Project Financing" shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer's obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

Project Finance Entity:

"Project Finance Entity" shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer's obligations under the corresponding power purchase agreement.

Projected PJM Market Revenues:

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Proportional Multi-Driver Project:

"Proportional Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Pseudo-Tie:

"Pseudo-Tie" shall have the same meaning provided in the Operating Agreement.

Public Policy Objectives:

"Public Policy Objectives" shall have the same meaning provided in the Operating Agreement.

Public Policy Requirements:

"Public Policy Requirements" shall have the same meaning provided in the Operating Agreement.

Qualifying Transmission Upgrade:

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

Queue Position:

"Queue Position" shall mean the priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Tariff, Part VI.

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 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:

“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.

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 seperately 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 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.

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.

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 for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource or a Capacity Storage Resource; or (v) used in association with restoration or black start service.

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.

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 Demand 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 Demand 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.

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 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 [1.5 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%)].

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 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, 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, 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.

v) Net Energy and Ancillary Services Revenue Offset

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.

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 PJM 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) of this Attachment DD 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) of this Attachment DD 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) of this Attachment DD 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.

<u>Attachment C</u>

Affidavit of Adam J. Keech

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER19-_____-000**
	)	

AFFIDAVIT OF ADAM J. KEECH
ON BEHALF OF PJM INTERCONNECTION, L.L.C.
REGARDING PERIODIC REVIEW OF VARIABLE RESOURCE REQUIREMENT CURVE SHAPE AND KEY PARAMETERS

Introduction

1. My name is Adam J. Keech. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I currently serve as the Executive Director, Market Operations for PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit in support of PJM's proposal in this proceeding to revise certain PJM Open Access Transmission Tariff ("Tariff") provisions as a result of this year's review, as required every four years under the Tariff, of the Variable Resource Requirement Curve ("VRR Curve") and key components of that curve. The components are the gross Cost of New Entry ("CONE") parameter 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"). The VRR Curve is used as the demand curve for procuring capacity in PJM's Reliability Pricing Model ("RPM") capacity market.

2. Specifically, my affidavit explains and supports: (a) PJM's determination to continue to base the VRR Curve on the Net CONE (i.e., CONE minus the EAS Offset) estimated for a combustion turbine peaking power plant ("CT Plant"); (b) PJM's determination to shift the VRR Curve to the left by 1%; and (c) PJM's assumption that the energy market offer of the reference CT Plant would include the 10% adder the Tariff allows for such offers.

Qualifications and Experience

3. I have served in my current position since 2016 but have served as Director or Senior Director of Market Operations since 2013 where I had very similar responsibilities. The Market Operations Departments at PJM are responsible for technical design, implementation, and clearing of all PJM electricity markets and include the Day-Ahead Market Operations Department, the Real-Time Market Operations Department, the Market Simulation Department, the Capacity Market Operations Department, and the Interregional Market Operations Department. The responsibilities of these departments include the Day-ahead and Real-time Energy Markets, Day-Ahead Scheduling Reserve Market, Regulation, Synchronized Reserve and Non-Synchronized Reserve Markets, Financial Transmission Rights and Reliability Pricing Model auctions,

the Market Efficiency Process, and Market-to-Market coordination between PJM and the Midcontinent Independent System Operator, Inc., and between PJM and the New York Independent System Operator.

4. In my capacity as Executive Director of the Market Operations Departments, I am directly responsible for the development of market rule changes through PJM's stakeholder process, oversight of the technical implementation of rule changes, and ensuring that PJM's market operations processes and market clearing results adhere to the requirements detailed in the Tariff and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"). As Executive Director of the Market Operations Departments, my basic responsibility is to make sure that PJM's markets are designed in a manner that leads to efficient, intuitive market outcomes that minimize the cost of procurement, meet system reliability needs, and incentivize market participants to act in a manner that promotes system reliability. Prior to assuming my leadership role in Market Operations, I served as Director of Dispatch for PJM where I was responsible for real-time system operations in the control room and compliance with North American Electric Reliability Corporation standards. Before that, I served as manager of PJM's Real-Time Market Operations Department for three years, where I was directly responsible for PJM's real-time markets including the Real-time Energy Market and the Regulation, Synchronized Reserve and Non-Synchronized Reserve Markets in addition to the Real-Time Security Constrained Economic Dispatch tool used by PJM's system operators.

5. I have worked at PJM since January 2003. I hold a Bachelor's of Science degree in Electrical Engineering from Rutgers University in New Brunswick, NJ, and a Master's of Science degree in Applied Statistics from West Chester University in West Chester, PA.

<u>It Remains Reasonable to Base the VRR Curve on the Net CONE of a CT Plant</u>

6. Since the adoption of RPM, the VRR Curve has been based on the Net CONE of a CT Plant. PJM does not propose at this time to change this long-standing reliance on a CT, which, as I explain, remains reasonable.

7. The well-accepted economic theory behind the capacity market's downward-sloping demand curve is that, over time, the market is expected to achieve an equilibrium where cleared capacity converges at the target Installed Reserve Margin, and all new economic generation—regardless of resource type—should converge at the same Net CONE. Based on this principle, PJM's independent consultants from The Brattle Group explained in their 2014 review of PJM's VRR Curve that "[o]ver the long-term, it should not matter which technology is selected for determining Net CONE as long as the chosen technology is economically viable."[1] In their 2018 review of the VRR Curve, Brattle affirmed that they "continue to believe" that "any technology that is economically

[1] 2014 Triennial Review Filing of PJM Interconnection, L.L.C., Docket No. ER14-2940-000, Attachment E, 2014 VRR Report at 27 (Sept. 25, 2014) ("2014 Triennial Review Filing").

viable in the long run could be selected for determining Net CONE."[2] So long as a CT plant remains an economic new entry option in the PJM Region, a CT-based Net CONE can still be consistent with the equilibrium Net CONE a reasonably designed VRR Curve is expected to produce. In my view, that condition is met here: CT plants, as a resource category, remain economic options for new entry into the PJM Region. While Brattle presents data on the large amount of combined cycle plant capacity added to the PJM Region, their data also shows over 1600 MWs of new combustion turbine plants added to PJM since RPM was adopted.[3] Indeed, as they also note, two new merchant CT Plants have been added since 2014.[4] Thus, even if not the largest new entry resource category, CT Plants have demonstrated their economic viability in the PJM Region by clearing RPM auctions. Brattle does not present a firm conclusion that CT Plants will *not* be viable. Rather, they state only "it is not clear" that CT Plants "will remain part of the supply mix in equilibrium."[5] As the regional transmission organization ("RTO"), 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. PJM's prudent choice is well supported by the facts, as I show below.

8. First, new CT Plants have the lowest project cost and are the quickest resources to bring to market. They can be added to the system in about three years and at lower direct project costs (on the order of $300 million) than CC plants (on the order of $1 billion).[6] Therefore these resources represent the cheapest and fastest generation technology that could be brought to the market should market signals indicate the need for new capacity. CT Plants also represent the generation technology that is most-dependent on capacity market revenues due to their typically high marginal operating costs and low capacity factors. This is not to say that Net CONE for a capacity market *must* in all cases be based on a peaking plant. Nor am I saying that a peaking plant should be the basis for the VRR Curve if the underlying resource type is uneconomic even with capacity market revenues. However, where a peaking resource class has proven to be viable and economic over many years, as is the case for CT plants in the PJM Region, it is reasonable, and highly consistent with the purpose of capacity markets, to anchor the VRR Curve with an estimate of the revenues such a peaking resource needs from the capacity market. Exhibit No. 1 to my affidavit, for example compares the capacity factor trends of CT and CC plants Monthly average CC capacity factors, which were in the 10% to 30% range in 2007 and 2008, have dramatically increased in just ten years, and are now in a range of about 50% to 70%. Monthly average CT capacity

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2 Attachment G, Exhibit No. 2, 2018 VRR Curve Report at 33 n.42 ("2018 VRR Curve Report").

3 Attachment E, Exhibit No. 2, 2018 CONE Study at 5, Figure 2 ("2018 CONE Study"); *see also id.* at 17, Table 8.

4 2018 CONE Study at 5 n.17 (citing addition of 340 MW Doswell Peaking Unit and 141 MW Perryman Unit 6).

5 2018 VRR Curve Report at 33 n.42.

6 2018 CONE Study at Table 9 and Table 10 (estimating "Total Capital Costs for, respectively, CT and CC plants in each CONE Area).

factors, by contrast, have remained in a range of about 2% to 10% since 2007 (perhaps increasing by a percent or two over that time). CT plants long have operated well to meet rapid changes in demand, and that essential need will not only continue, but evolve and expand with the changing resource mix. Moreover, RPM's VRR Curve has been based on a CT Plant since 2007. New entry decisions over that time, including by new CTs, new CCs, and uprates, have undoubtedly factored in, to some degree, that stable auction design assumption. That stability thus provides foundation and assurance for the new entry decisions on which resource adequacy depends. Maintaining the same resource type also avoids perceived opportunistic switching to units with more favorable economics in any given year.

9. Second, there is greater risk of mis-estimating a CC Net CONE than there is of mis-estimating a CT Net CONE. This is because the cost to build a new plant can be reliably estimated within a reasonable margin of error, but the future energy and ancillary service market revenues the new plant will receive are not. These projected revenues are used in the calculation of the EAS offset used to derive Net CONE. The larger and more unpredictable these revenues are, the less likely it is that the Net CONE can be accurately estimated. A CC Plant depends far more on energy market revenues than does a CT Plant and thus a CC Plant is far more susceptible to mis-estimation than a CT Plant in calculating the EAS offset and ultimately the Net CONE. Brattle's Net CONE estimates, for example, expect that the reference CC plant would depend on the energy market for about 61% of its revenue requirement, while the reference CT plant would rely on the energy market for only about 27% of its revenue requirement.[7] A CC Net CONE estimate, therefore, is more likely to be inaccurate (compared to actual net new entry costs for the subject plant type) than a CT Net CONE estimate. This can have a detrimental effect on the VRR Curve's ability to maintain resource adequacy.

10. Third, Brattle's long-run simulations lend support to PJM's proposed retention of a CT-based Net CONE, and quantify the reliability risks if RPM was switched to a CC-based Net CONE, and that Net CONE was underestimated. The simulations cover a variety of supply and demand alternatives, but also assess the reliability and cost consequences if the Net CONE used for the VRR Curve is underestimated. One underestimation scenario considers what would happen if the Net CONE needed at equilibrium by new entry plants is 20% higher than the administrative estimate of a CC-based Net CONE embedded in the VRR Curve. Another scenario considers the consequences of using a CC Net CONE in the VRR Curve when the Net CONE needed by new entrants at equilibrium is actually a substantially higher, CT-based Net CONE.

11. Brattle's modeling shows that PJM's recommended curve (designated in the tables as curve "B") satisfies the 1-in-10 LOLE standard on average under all tested scenarios.[8] PJM's proposed curve achieves this reliability while lowering consumer costs

7 2018 VRR Curve Report at vii, Table ES-1.

8 *Id.* at 66-67, Tables 11 & 12 (Curve "B" row; "Average LOLE" and "Stress" LOLE columns).

by $111 million per year, compared to the current VRR Curve. Under the scenario where the VRR Curve is based on a CT, but the market's true new entry is a CC Net CONE, PJM's proposed curve performs even better on reliability metrics (because supply is more abundant in that scenario), and saves consumers on average $74 million each year, compared to the current curve.[9]

12. Brattle's proposed CC-based VRR Curve (designated in the tables as curve "E"), by contrast, fails reliability standards if the CC Net CONE estimate is understated. That curve meets reliability standards if the market's true new entry cost is close to Brattle's CC estimate, and results in annual consumer costs $138 million lower (i.e., 1.7% lower) than PJM's proposed curve.[10] However, if Brattle's CC Net CONE estimate is 20% below the market's true new entry cost due to, for example, inaccurate EAS revenue estimates, Brattle's preferred curve would fail the 1-in-10 LOLE standard, resulting in an expected 1.6 loss of load events every ten years.[11] This is not a far-fetched scenario. If Brattle's CC Net CONE is understated by 20%, then the "true" Net CONE would still be only about $160/MW-day, or less than half the Net CONE used in the 2018 BRA. Moreover, if the true new entry cost instead tracks a CT Net CONE, then the Brattle recommended CC-based VRR Curve would perform very poorly, i.e., 3.3 loss of load events every 10 years.[12]

13. A CC Net Cone, therefore, *might* be reasonable, but it carries greater reliability risk, and that risk arises from the very feature of a CC Net CONE that is most vulnerable, i.e., the inherent uncertainty of a Net CONE calculation that relies to a much greater degree on estimates of energy market revenues.

14. An added benefit of using a CT Plant as the CONE Reference Resource is that it will incent investment in both CT and CC Plant technologies. This is important because both resource types have the needed operational flexibility required to manage a power system with growing levels of uncertainty of demand levels and intermittent resource operation.

15. For all of these reasons, continuing to base the VRR Curve on a CT plant is a sound, reasonable, and prudent choice.

<u>Shifting VRR Curve 1% to the Left</u>

16. In the 2014 VRR Curve Review, PJM largely accepted Brattle's recommendations, but also proposed a shift of the curve 1% to the right, as a conservative approach to address substantial supply uncertainty and the associated difficulty in using

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9 *Id.* at 66, Table 11.

10 *Id.*

11 *Id.*

12 *Id.* at 67, Table 12.

historical resource mix data as a reliable indicator of the future supply base.[13] PJM noted several sources of this uncertainty: large scale generation retirements due to the United States Environmental Protection Agency's Mercury and Air Toxics Standards ("MATS") rule, the emergence of low-cost shale gas and the increasing efficiency of natural gas combined-cycle technology that could drive further resource retirements; the D.C. Circuit Court's vacatur of Order No. 745 causing uncertainty of the use of demand response in our markets; and uncertainty in the manner in which states would implement the EPA's greenhouse gas rule.

17. The reasons for right-shifting the VRR curve that PJM cited in 2014 have been resolved or are much less of a concern. The wave of MATS-related retirements is essentially complete; and the market has had nearly ten years to react to the emergence of shale gas. Moreover, the U.S. Supreme Court reversed the D.C. Circuit and affirmed the Commission's authority to accept demand resource offers in the capacity market. Finally, the greenhouse gas rule has not been implemented. While there currently is a potential for a significant amount of near-term economic retirements, that potential does not pose the same resource adequacy challenges as the unique confluence of expected events that raised legitimate concerns in 2014 of simultaneous large-scale retirements. Moreover, as to today's risks of economic retirements, RPM has demonstrated its ability to manage such retirements by attracting new capacity or incentivizing existing capacity to stay online as the market tightens.[14] The rightward shift expressly warranted as a conservative response to that unusual confluence of events; therefore, is no longer warranted, and PJM agrees with Brattle's recommendation to reverse this shift. PJM therefore proposes now to revise the shape of the VRR Curve by reversing the adjustment adopted four years ago, i.e., to now shift the VRR Curve 1% to the left.

<u>Reflecting 10% Energy Market Offer Adder in EAS Offset</u>

18. The current EAS method estimates energy revenues in part based on fuel costs. However, the EAS rules do not presently recognize the 10% margin that the energy market rules allow to be included in the cost-based energy market offers of actual generation resources.[15] Inasmuch as this adder is intended to account for uncertainties in the determination of these energy market participation costs, the 10% adder should likewise be incorporated into the cost-based energy market offer assumed for the Reference Resource in the EAS estimating method's Peak-Hour Dispatch rules. These same uncertainties, e.g., assumptions regarding the applicable gas index hub, day-ahead versus intra-gas use, and assigned LMP) would confront the seller of a Reference Resource if it were preparing an energy market offer.

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13 2014 Triennial Review Filing, Attachment C, Affidavit of Dr. Paul M. Sotkiewicz, at PP 1-13.

14 *See, e.g.*, *Resource Investment in Competitive Markets*, PJM Interconnection, L.L.C., at 30-34. (May 5, 2016), https://www.pjm.com/~/media/library/reports-notices/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx.

15 Operating Agreement, Schedule 1, section 6.4.2.

19. Therefore, it is reasonable and consistent with the approved energy market rules to apply the 10% margin to the cost-based energy market offer of the reference resource. Introduction of the 10% margin into the Peak-Hour Dispatch of the reference resource provides an offset around these uncertainties and also accounts for differences between the key assumptions made for the Reference Resource relative to actual attributes of a similarly-situated representative resource.

Use of Selective Catalytic Reduction in Rest-of RTO Area

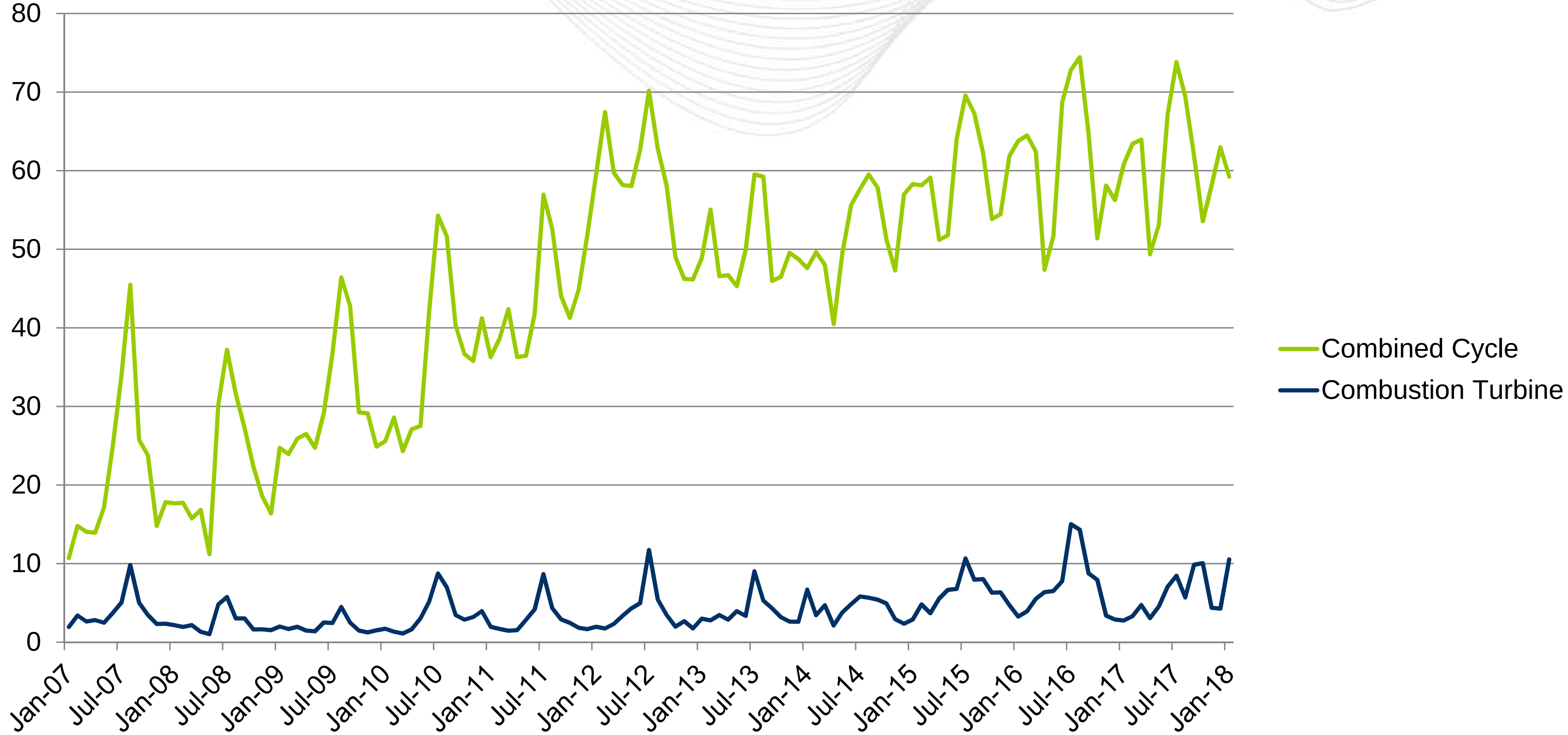
20. PJM made one further change from Brattle's CONE estimates. Brattle assessed that a CONE Plant located in the Rest of RTO CONE Area would not install selective catalytic reduction ("SCR") technology and carbon monoxide ("CO") controls for air emissions, because it would not be compelled by law to do so. Such a plant, however, has an economic incentive in RPM to add SCR and CO control technology, even if not otherwise required. Absent these controls, the plant might face severe run-time restrictions, which could significantly impede the plant's ability to run at peak times, making it more likely to incur performance penalties under PJM's capacity performance rules. PJM therefore asked Brattle to include SCR and CO control costs in the CONE estimate for the Rest of RTO CONE Area.

21. This concludes my affidavit.

Exhibit No. 1

Capacity Factor Trends

Capacity Factor Trends



UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Docket No. ER19-___-000**

VERIFICATION

Adam J. Keech, being first duly sworn, deposes and states that he is the Adam J. Keech referred to in the foregoing document entitled "Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C. Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

Adam J. Keech

Subscribed and sworn to before me, the undersigned notary public, this 11th day of October 2018.

Linda Spreeman
Notary Public

My Commission expires: November 17, 2019

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Linda Spreeman, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Nov. 17, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

Attachment D

Affidavit of M. Gary Helm

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER19-_____-000**
	)	

AFFIDAVIT OF M. GARY HELM
ON BEHALF OF PJM INTERCONNECTION, L.L.C.
REGARDING PERIODIC REVIEW OF VARIABLE RESOURCE REQUIREMENT CURVE SHAPE AND KEY PARAMETERS

Introduction

1. My name is M. Gary Helm. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I currently serve as Lead Market Strategist for PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit in support of PJM's proposal in this proceeding to revise certain PJM tariff provisions as a result of this year's review, as required every four years under PJM's tariff, of the Variable Resource Requirement curve ("VRR Curve") and key components of that curve. The components are the gross Cost of New Entry ("CONE") parameter and the method to estimate the net revenues the CONE plant would earn in the PJM Region's energy and ancillary services markets. The VRR Curve is used as the demand curve for procuring capacity in PJM's capacity market, known as the Reliability Pricing Model or RPM.

2. Specifically, my affidavit explains and supports PJM's determination to base the estimated after-tax weighted average cost of capital ("ATWACC") component of the CONE on a cost of debt of 6.0%, resulting in an estimated ATWACC of 8.2%.

Qualifications and Experience

3. I have served in my current position since September 2010. As Lead Market Strategist, I evaluate strategic issues for PJM, focusing on the impact of environmental legislation/regulation, fuel supply and infrastructure, generation technology, and broad economic trends on electricity markets and grid operations.

4. I co-authored "Coal Capacity at Risk for Retirement in PJM: Impact of EPA Transport and Hazardous Air Pollutant Rules." I was the PJM project manager for the Eastern Interconnection Planning Collaborative's Gas-Electric System Interface Study. Additionally, I provided analysis and advice for the 2011 and 2014 VRR Curve parameter reviews. Prior to PJM, I managed air quality issues, including policy, strategy, permitting and environmental markets, for Conectiv Energy. There I participated in the development, construction, commissioning and startup of several natural gas combined-cycle and peaking facilities. I began my energy career with engineering firm

Gilbert/Commonwealth, where I led teams in performance testing and tuning of utility boilers.

5. I have a Master of Finance degree, a Master of Engineering degree and a Bachelor of Science degree in Horticulture from Pennsylvania State University.

Estimated ATWACC and Cost of Debt

6. As explained in the two affidavits concurrently submitted in this proceeding by Dr. Samuel Newell, Mr. Michael Hagerty, and Mr. Sang H. Gang and by Mr. Johannes Pfiefenberger and Dr. Bin Zhou, PJM retained the Brattle Group ("Brattle") and Sargent & Lundy to assist PJM in the review and updating of the CONE estimate, including the ATWACC value used in that estimate. They completed their review and set forth their analysis and recommendations in a report entitled "PJM Cost of New Entry: Combustion Turbines and Combined Cycle Plants with June 1, 2022 Online Date" ("2018 CONE Study"), a copy of which is included as Exhibit No. 2 to the Newell/Hagerty/Gang affidavit. In order to develop the Gross CONE, Brattle used the same analytical approach it used in its PJM CONE reviews in 2014 and 2011, which were accepted by the Commission. This approach involved developing financial assumptions to be used in the determination of Gross CONE. The financial assumptions include the ATWACC, the debt to equity ratio, the cost of debt and the return on equity. Brattle estimated the recommended ATWACC by an empirical analysis of publicly-traded merchant generation companies, including recent mergers and acquisitions, and recognizing significant changes to corporate tax law enacted in December 2017. Based on Brattle's analysis, the 2018 CONE Study recommended an ATWACC of 7.5%.

7. The 2018 CONE Study was completed in April 2018. Brattle updated their ATWACC estimate in August 2018, and found increases (relative to the earlier estimate) in both the U.S. risk-free rate and the cost of debt. As set forth in a memo they provided to PJM and PJM stakeholders dated August 21, 2018, Mr. Pfiefenberger and Dr. Zhou estimated that the ATWACC for the new entry plant would be 8.0%. A copy of that memo (the "August 21 Supplement") is shown in Exhibit No. 2 to their affidavit. The 2018 CONE Study estimated the capital structure for the new entry project to be 60% debt to 40% equity based upon the five-year average debt to equity ratio of a set of publicly traded merchant generation companies.[1] In the August 21 Supplement, Brattle adjusted this estimate to 55% debt to 45% equity to incorporate its further analysis and information supplied by stakeholders in the PJM quadrennial review process.

8. In the 2018 CONE Study, Brattle estimated a 6.5% cost of debt based upon a combination of B-rated and BB-rated company specific bond yields. In the August 21 Supplement, Brattle revised this estimate to 5.5%, citing the reduction in the estimated debt ratio from 65% to 55%, and the belief that a BB rating is more likely associated with the lower leverage.[2]

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1 2018 CONE Study at 39-40.

2 August 21 Supplement at 2.

9. While generally I find Brattle's analysis reasoned and well-supported, in my opinion it is reasonable and prudent to maintain the earlier assessment that a merchant generator of the type that would sponsor a new entry plant would likely have a credit rating somewhere between B and BB, rather than being rated BB alone. The credit rating of the US Independent Power Producers ("IPPs") that Brattle analyzed as part of the 2018 CONE Study were rated B and BB. While two of the companies were purchased, those credit ratings are still a reasonable representation of the credit ratings of entities that may finance new power plants.

10. With the expected credit rating maintained at a mix of B-rated and BB-rated bonds, a 6% cost of debt is appropriate. This assessment follows from the 3-year average of ratings-based index interest rates of 5.1% for BB-rated and 6.5% for B-rated bonds.[3] Similar to the reasoning in the August 21 Supplement, this cost of debt reflects the current rising interest rate environment, which was confirmed by Federal Reserve Bank Chairman Jerome Powell in a September 26, 2018 press conference, in which he stated the Federal Reserve Bank's "views on appropriate policy through 2020 are unchanged since the June meeting" in which they set expectations for gradual increases in interest rates.[4]

11. In the August 21 Supplement, Brattle recommended a cost of equity of 13% based upon its consistency with its recommended capital structure, with which PJM agrees.[5] As such, with the adjustment in the cost of debt, PJM recommends adjusting the ATWACC to 8.2%, based on the formula:

$$ATWACC = r_D(1 - T_c)\,D/V + r_E\,E/V$$ [6]

Where:
r_D and r_E = the expected returns on debt and equity
T_c = the marginal rate of corporate tax
D and E = the market values of debt and equity (V = D + E)

12. This concludes my affidavit.

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3 These values are reported on the website of the St. Louis regional office of the U.S. Federal Reserve, and are available at: https://fred.stlouisfed.org/series/BAMLH0A1HYBBEY https://fred.stlouisfed.org/series/BAMLH0A2HYBEY

4 *Transcript of Chairman Powell's Press Conference*, at 3 (Sept. 26, 2018), https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20180926.pdf.

5 August 21 Supplement at 2.

6 R. Brealey, S. Myers, and F. Allen, *Principles of Corporate Finance*, McGraw-Hill/Irwin, 8th ed. 2006.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Docket No. ER19-___-000**

VERIFICATION

M. Gary Helm, being first duly sworn, deposes and states that he is the M. Gary Helm referred to in the foregoing document entitled "Affidavit of M. Gary Helm on Behalf of PJM Interconnection, L.L.C. Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

Subscribed and sworn to before me, the undersigned notary public, this 11 day of October 2018.

Linda Spreeman
Notary Public

My Commission expires: November 17, 2019

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Linda Spreeman, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Nov. 17, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

<u>Attachment E</u>

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. ER19-______-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 2011 and 2014 PJM CONE studies and provided affidavits in ensuing litigation, which informed the Net CONE values PJM used in its principal annual capacity auctions for the last six years. In addition, Dr. Newell's extensive related experience in market design for resource adequacy for ISO-NE, PJM, NYISO, MISO, and ERCOT 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 also co-authored the 2014 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 more than 20 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and RTO market rules. Prior to joining The Brattle Group, he was the Director of the Transmission Service at Cambridge Energy Research Associates and previously a Manager in the Utilities Practice at A.T.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 more than 5 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.Sc. in Chemical Engineering from the University of Notre Dame.

5. Mr. Gang has significant experience assessing power plant technologies and estimating plant capital costs, operation and maintenance ("O&M") costs, and performance characteristics. Within the last two years, Mr. Gang has been leading Sargent & Lundy's electric power resource planning projects including evaluation of various generation and interconnection options. Mr. Gang also led the Sargent & Lundy 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 10 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, 2017, PJM retained Brattle 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, 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 cost 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 results of the analysis completed by Brattle and S&L are set forth in a report entitled "PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date" ("2018 CONE Study"). A copy of the 2018 CONE Study, which was prepared under our direction and supervision, is included as Exhibit No. 2 to our affidavit.

10. Following the release of the 2018 CONE Study, PJM conducted a stakeholder process to review the report and solicit input on the assumptions. As a result of those discussions, we determined to make changes to our CONE estimates in two

respects. The effects of those two adjustments on our CONE estimates largely offset each other.

11. First, Brattle's estimates in the 2018 CONE Study assumed that new entry plant developers would need to pay sales tax in each of the four states where the new entry plant is assumed to be installed (i.e., New Jersey, Pennsylvania, Maryland, and Ohio), but Brattle's further research (and input from the Independent Market Monitor for the PJM Region) revealed that equipment and materials are exempt from state sales tax. Therefore, as reflected in a memo Brattle provided to PJM and the PJM stakeholders dated September 26, 2018, we removed sales tax on equipment and materials from the Gross CONE estimates for all CONE Areas. A copy of that memo is attached to our affidavit as Exhibit No. 3.

12. Second, as set forth in the accompanying affidavit of Johannes Pfeifenberger and Bin Zhou, the 2018 CONE Study (completed in April, 2018) estimated that the after-tax weighted average cost of capital ("ATWACC") for the new entry plant would be 7.5%. Brattle updated that estimate in August 2018, and found increases (relative to the earlier estimate) in both the U.S. risk-free rate and the cost of debt. As set forth in a memo provided to PJM and PJM stakeholders dated August 21, 2018 (a copy of which is attached to Mr. Pfeifenberger and Dr. Zhou's affidavit), Brattle estimated that the ATWACC for the new entry plant is 8.0%.

13. This affidavit summarizes the methodology and results of our study, with modifications requested by PJM. The 2018 CONE Study includes detailed estimates for both a combustion turbine plant and a combined cycle plant. PJM has determined to base its proposal in this proceeding on our combustion turbine ("CT") plant CONE estimate; this affidavit therefore focuses on that aspect of the 2018 CONE Study.

14. Our starting point for estimating CONE was to determine representative locations and technical specifications for the natural gas-fired CT plant. 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 2018 CONE Study, we determined the representative CT plant should be configured with one General Electric 7HA.02 gas turbine. We further determined, based on our experience and analysis, that the new entry plant should include evaporative cooling for power augmentation and dual-fuel capability. We determined that the new entry plant should include selective catalytic reduction ("SCR") technology and carbon monoxide ("CO") catalyst environmental controls to reduce air pollutant emissions in all CONE Areas except CONE Area 3 (Rest of RTO). Based on PJM's request, we developed an alternative CONE estimate for the CONE Area 3 CT that included

an SCR and CO catalyst. The results we present below are based on the PJM-requested plant design with the SCR and CO catalyst included for the CONE Area 3 CT. The net summer installed capacity of such a plant ranges from 344 to 355 MW depending on the ambient atmospheric conditions assumed in each location, with a net heat rate (Higher Heating Value) of approximately 9.255 to 9.274 MMBtu/MWh.

16. Based on this configuration, we estimated capital and fixed O&M costs for each CONE Area. More specifically, 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. The 2018 CONE Study describes the bases for each of these estimates.

17. We then calculated a levelized CONE value for the CT plant in each CONE Area employing a reasonable discount rate based on the estimated ATWACC value, as further explained in the affidavit of Mr. Pfeifenberger and Dr. Zhou. We calculated levelized costs assuming 20 years of cash flows that are constant in nominal terms. Our reasons for assuming level-nominal cash flows (i.e., declining in real terms at the rate of inflation) are explained in the 2018 CONE Study.

18. As set forth in the accompanying affidavit of PJM's Lead Market Strategist M. Gary Helm, PJM takes a different view of the proper debt cost, and resulting ATWACC, for the new gas-fired plant. Thus, PJM chose to adopt a debt cost of 6.0% and ATWACC of 8.2%, instead of Brattle's 5.5% debt cost and 8.0% ATWACC recommendation. As Mr. Pfeifenberger and Dr. Zhou explain in their affidavit, while the PJM-adopted ATWACC is higher than our recommendation, PJM's 8.2% ATWACC recommendation is within the range of available market evidence for merchant generation.

19. At PJM's request, we prepared and present in this affidavit the CONE values for each CONE Area using PJM's 8.2% ATWACC and assuming the installation of an SCR and CO catalyst in CONE Area 3 (Rest of RTO). All other assumptions, estimates and determinations were determined by Brattle and S&L and set forth in the 2018 CONE Study, the August 21 memo on the updated ATWACC, and the September 26 memo on the adjustments to the CONE values.

20. The estimated CONE for the reference CT plant in each CONE Area with an online date of June 1, 2022 based on the 2018 CONE Study and other materials noted herein are as shown in Table 1.

Table 1
CT Plant CONE Estimates

CONE Area	**CT CONE** *($/MW-year)*
CONE Area 1	$108,000
CONE Area 2	$109,700
CONE Area 3	$105,500
CONE Area 4	$105,500

21. The above CONE values assume that certain major maintenance costs are recovered as variable O&M through energy market offers, consistent with PJM's expressed intention to modify its energy market rules to provide for such recovery. At PJM's request, we have also prepared CONE estimates for each CONE area that assume that these major maintenance costs are instead recovered through the capacity market. Those estimates, including all assumptions employed in the Table 1 estimates, but now also including the referenced major maintenance costs, are as shown in Table 2.

Table 2
CT Plant CONE Estimates (with Major Maintenance)

CONE Area	**CT CONE** *($/MW-year)*
CONE Area 1	$126,700
CONE Area 2	$128,200
CONE Area 3	$124,500
CONE Area 4	$124,700

22. The PJM Tariff also states a value for variable O&M costs of the CT new entry plant, for use in connection with estimating the plant's expected PJM energy market revenues. Assuming plant major maintenance costs are recovered in the energy market, we estimate the variable O&M value to be $6.93 per MWh, based on $5.83/MWh for major maintenance and $1.10/MWh for consumables, waste disposal and other variable O&M. At PJM's request, we converted the starts-based major maintenance costs reported in the 2018 CONE Study to an hours-based value using major maintenance costs of $23,464/start, an average runtime of 11 hours per start, and average capacity of 366 MW across CONE Areas (accounting for the higher capacity of the CONE Area 3 CT with the SCR and CO catalyst). PJM would use this variable O&M value if the CONE values listed in Table 1 are adopted. If those major maintenance costs are not included in energy market offers and the CONE values in Table 2 are instead adopted, we estimate the variable O&M of the reference CT plant to be $1.10 per MWh.

23. PJM also is proposing, based on our analyses and recommendations, two revisions to the Tariff procedures for annual revisions to the Gross CONE. PJM uses a composite index of generation plant capital costs to adjust the Gross CONE

values each year between the Tariff-mandated periodic reviews. The composite weights cost indices published by the U. S. Department of Commerce's Bureau of Labor Statistics for labor (20%), turbines (30%), and materials (50%). We recommended that PJM slightly change the weightings of these components to better accord with the new Gross CONE estimates. As shown in the 2018 CONE Study, the estimated capital costs for the CT plant entering service in 2022 break down as approximately 22% labor, 26% turbines and 53% materials.[1] We therefore recommended, and PJM agreed, to weight the indices as 20% labor, 25% turbines, and 55% materials.

24. Brattle also has recommended a further annual change to recognize a significant change in tax law that would affect the cost of the new entry plant. Specifically, the Tax Cuts and Jobs Act of 2017 ("TCJA") temporarily increased bonus depreciation to 100%, but then phased it down by 20% each year beginning January 1, 2023.[2] Bonus depreciation is a form of highly accelerated tax depreciation that can be applied immediately upon placing a depreciable asset in service. Per the TCJA, bonus depreciation is allowed for companies not classified as public utilities up to 100% of tax basis. This reduces the Gross CONE for a merchant new entry plant entering service in June 1, 2022, as assumed in the 2018 CONE Study, and that reduction is reflected in the CONE values presented here. New plants entering service in subsequent years, however, will have progressively less favorable tax treatment, as the 100% bonus depreciation phases down by 20% each year.[3] As shown in the 2018 CONE Study, we calculate that this known, enacted change will increase CONE for a new CT plant by 2.2% each year the bonus depreciation phases down by another 20%. We therefore recommended, and PJM agreed to adopt, escalation of the Gross CONE values (after applying any change based on the BLS composite index) each year using a 1.022 gross-up factor. We note that the bonus depreciation phase-down is not completed until December 31, 2026, so this proposed annual adjustment will remain appropriate for each Delivery Year expected to be covered by the current quadrennial review.

25. This concludes our affidavit.

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1 Values may not add up to 100% due to rounding.

2 *See* Internal Revenue Code section 168(k)(6).

3 A plant entering service in 2023, for example, can claim bonus depreciation of 80%, while a plant entering service in 2024 can claim 60%.

Exhibit No. 1

Samuel A. Newell, John M. Hagerty and Sang H. Gang Qualifications

SAMUEL A. NEWELL
Principal

Boston, MA | +1.617.234.5725 | Sam.Newell@brattle.com

Dr. Samuel Newell is an expert in electricity wholesale markets, market design, generation asset valuation, demand response, integrated resource planning, and transmission planning, including in systems with high penetration of variable energy resources. He has 20 years of experience supporting clients throughout the U.S. in electricity regulatory, litigation, and business strategy matters. He frequently provides testimony and expert reports to Independent System Operators (ISOs), the FERC, state regulatory commissions, and the American Arbitration Association.

Dr. Newell 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.

Prior to joining The Brattle Group in 2004, Dr. Newell was the Director of the Transmission Service at Cambridge Energy Research Associates. Before that, he was a Manager in the Utilities Practice at A.T. Kearney.

AREAS OF EXPERTISE

- Electricity Market Design and Analysis
- Transmission Planning and Modeling
- Integrated Resource Planning
- Generation and Storage Asset Valuation
- Demand Response (DR) Resource Potential and Market Impact
- Gas-Electric Coordination
- RTO Participation and Configuration
- Energy Litigation
- Tariff and Rate Design
- Business Strategy

EXPERIENCE

Electricity Market Design and Analysis

- **PJM's Capacity Market Reviews**. For PJM, conducted all four official reviews of its Reliability Pricing Model (2008, 2011, 2014, and 2018). 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. Submitted testimonies before FERC and participated in settlement discussions.

- **Harmonizing New York's Wholesale Energy Market and Environmental Goals through Carbon Pricing**. Led a Brattle team to work 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.
- **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. Authored report critiquing PJM's Fast-Start proposal, which NextEra and other parties filed with 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 report with FERC.
- **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.
- **Response to DOE's "Grid Reliability and Resiliency Pricing" Proposal**. For a broad range of stakeholders opposing the rule, provided an evaluation of the proposed rule that they attached to their filing before FERC. Evaluated the need (or lack thereof) for bolstering reliability and resilience by supporting resources with a 90-day fuel supply, estimated the likely cost of the rule, and described the incompatibility of DOE's proposed solution with the principles and function of competitive wholesale electricity markets.
- **Energy Market Power Mitigation in Western Australia**. Led a Brattle team to help the Government of 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.
- **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.

- **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.
- **Buyer Market Power Mitigation**. 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.
- **Investment Incentives and Resource Adequacy 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 at the target level; and (3) evaluate options to enhance long-term resource adequacy while maintaining market efficiency. Worked with ERCOT staff to understand the relevant aspects of their operations and market data. Performed probabilistic simulation analyses of prices, investment costs, and reliability. Findings 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-authored a report estimating the economically-optimal reserve margin. Collaborated with Astrape Consulting to construct a series of economic and reliability modeling simulations accounting for uncertain weather, generation outages, and multi-year load forecasting errors. Incorporated 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, scarcity pricing provisions under the ORDC, and load-shed events.

- **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.
- **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.
- **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.
- **Capacity Auction Design for Western Australia**. For Western Australia's Public Utility Office, drafted a whitepaper and advised on the high-level design for a new forward auction-based capacity market. Subsequently drafted whitepapers and advised on auction parameters, market power mitigation, and administrative aspects of implementing a forward capacity market.

- **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.
- **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'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 extensive 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.
- **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.
- **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.
- **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.
- **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."
- **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.
- **LMP Impacts on Contracts**. For a West Coast client, 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.
- **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.

Transmission Planning and Modeling

- **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 New York. 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 in any case; reduced costs of integrating renewable resources Upstate; and tax receipts. Identified the projects with the 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.
- **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 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.
- **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.

- **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.
- **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**. For a large, geographically diverse group of clients, performed an in-depth study identifying the major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions to the bottlenecks. Worked with transmission engineers from multiple 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 highly 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 in Connecticut and Long Island.
- **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.

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 the 2008, 2009, 2010, 2012, and 2014 Plans)**. For the two major utilities in CT and the CT Dept. of Energy and Environmental Protection (DEEP), led the analysis for five successive integrated resource plans. 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.

Generation and Storage Asset Valuation

- **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 in five years. Reviewed comparables. Analyzed electricity markets in New England, New York, Texas (post-tightening of the market in 2018), 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 market-based revenue forecast for energy and capacity. Evaluated the implications of several detailed 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.

Demand Response (DR) Resource Potential and Market Impact

- **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 biggest, most cost-effective opportunities 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 the 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 the short-term energy market price impact and addressed the long-run equilibrium offsetting effects through several plausible 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. Critiqued 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

- **Demand Response Arbitration.** 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 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 nascent venture to build and operate cogen 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 their 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 large 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 potential value client could bring to each

potential customer. Worked directly with company president to translate findings into a marketing strategy.

- **Distributed Generation (DG) Market Assessment**. For the unregulated division of a major utility, performed a market assessment of DG technologies. Projected future market sizes by market segments in the U.S.
- **Fuel Cells**. For a European fuel cell component manufacturer, acted as a technology and electricity market advisor for a larger consulting team developing a market entry strategy in the U.S.

TESTIMONY and REGULATORY FILINGS

Before the Federal Energy Regulatory Commission, Docket Nos. EL16-49-000, ER18-1314-000, ER18-1314-001, EL18-178-000 (Consolidated), Affidavit of Kathleen Spees and Samuel A. Newell Regarding the Need for a Self-Supply Exemption from Minimum Offer Price and Other Policy Supported Resource Rules on behalf of Dominion Energy Services, Inc. and Virginia Electric and Power Company, October 2, 2018.

Before the Federal Energy Regulatory Commission, Docket Nos. EL17-32-000 and EL17-36-000, Prefiled Comments of Samuel A. Newell, Kathleen Spees, and Yingxia Yang on behalf on behalf of the Natural Resources Defense Council: "Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM," April 15, 2018; presented oral testimony on the Seasonality Panel at FERC's Seasonal Capacity Technical Conference on April 24, 2018.

Before the Federal Energy Regulatory Commission, Docket No. EL18-34-000, Samuel A. Newell, Pablo A. Ruiz, and Rebecca C. Carroll, "Evaluation of PJM's Fast-Start Pricing Proposal," report prepared for NextEra Energy Resources and attached to *Reply Brief of Joint Commenters*, March 14, 2018.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, oral testimony and cross examination on the electricity market impacts of the proposed Northern Pass Transmission Project, October 26-27, 2017.

Before the Federal Energy Regulatory Commission, Docket No. AD17-11-000, Prefiled Comments of Samuel A. Newell re "Reconciling Wholesale Competitive Markets with State Polices," April 25, 2017; and oral testimony on Industry Expert Panel at the Technical Conference on May 2, 2017.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Supplemental Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project--Supplemental Report," April 17, 2017.

Before the Federal Energy Regulatory Commission, Docket No. ER17-284-000, filed "Response of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," January 13, 2017.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Direct Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project," December 30, 2016.

Before the Federal Energy Regulatory Commission, Docket No. ER17-284-000, filed "Testimony of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," November 1, 2016.

"Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," Appendix 1 to Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives, Trial Staff Final Report, *Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades*, New York State Department of Public Service, Matter No. 12-02457, Case No. 12-T-0502, September 22, 2015. Presented to NYISO and DPS Staff at the Technical Conference, Albany, NY, October 8, 2015.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, filed "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Comments on LEI's June 2015 Report and Recommendations for a Regional Analysis," November 18, 2015.

Before the Federal Energy Regulatory Commission, Docket No. ER14-2940-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Variable Resource Requirement Curve," for use in PJM's capacity market, November 5, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER15-68-000, filed "Affidavit of Dr. Samuel A. Newell on behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's Minimum Offer Price Rule, October 9, 2014.

Before the Texas House of Representatives Environmental Regulation Committee, Hearing on the Environmental Protection Agency's Newly Proposed Clean Power Plan and Potential Impact on Texas, invited by Committee Chair to present, "EPA's Clean Power Plan: Basics of the Rule, and Implications for Texas," Austin, TX, September 29, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, September 25, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," September 25, 2014.

Before the Public Utilities Commission of the State of Colorado, Proceeding No. 13F-0145E, "Answer Testimony and Exhibits of Samuel A. Newell on Behalf of Tri-State Generation and Transmission

Association, Inc.," regarding an analysis of complaining parties' responses to Tri-State Generation and Transmission Association, Inc.'s Third Set of Data Requests, Interrogatory, September 10, 2014.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Analysis of the Maine Energy Cost Reduction Act in New England Gas and Electricity Markets," July 11, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve," April 1, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry For The Forward Capacity Market Demand Curve," April 1, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-616-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of ISO New England Inc.," and accompanying "2013 Offer Review Trigger Prices Study," regarding the Minimum Offer Price Rule new capacity resources in capacity auctions, December 13, 2013.

Before the American Arbitration Association, provided expert testimony (deposition, written report, and oral testimony at hearing) in a dispute involving the acquisition of a demand response company, July-November, 2013. (Non-public).

Before the Public Utility Commission of Texas, at a workshop on Project No. 40000, presented "Report On ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates Prepared By The Brattle Group," on behalf of The Electric Reliability Council of Texas (ERCOT), June 25, 2013. Subsequently filed additional comments, "Additional ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates," July 29, 2013.

Before the Federal Energy Regulatory Commission, Docket No. ER13-535-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, December 28, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-513-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC," in support of PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's capacity market, November 21, 2012.

Before the Texas House of Representatives State Affairs Committee, Hearing on the issue of resource adequacy in the Texas electricity market, presented "The Resource Adequacy Challenge in ERCOT," on behalf of The Electric Reliability Council of Texas, October 24, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "Resource Adequacy in ERCOT: 'Composite' Policy Options," and "Estimate of DR Potential in ERCOT" on behalf of The Electric Reliability Council of Texas (ERCOT), October 25, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "ERCOT Investment Incentives and Resource Adequacy," September 6, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "Summary of Brattle's Study on ERCOT Investment Incentives and Resource Adequacy," July 27, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-___-000, Affidavit of Dr. Samuel A. Newell on Behalf of SIG Energy, LLLP, March 29, 2012, Confidential Exhibit A in Complaint of Sig Energy, LLLP, SIG Energy, LLLP v. California Independent System Operator Corporation, Docket No. EL 12-___-000, filed April 4, 2012 (Public version, confidential information removed).

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, January 13, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed December 1, 2011.

Before the Federal Energy Regulatory Commission, Docket Nos. ER11-4069 and ER11-4070, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies, re: the public policy, congestion relief, and economic benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the Federal Energy Regulatory Commission, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the public policy, reliability, congestion relief, and economic benefits of the Atlantic Wind Connection Project, filed December 20, 2010.

"Economic Evaluation of Alternative Demand Response Compensation Options," whitepaper filed by ISO-NE in its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000, October 13, 2010 (with K. Madjarov).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Notice of Proposed Rulemaking regarding wholesale compensation of demand response, May 13, 2010 (with K. Spees and P. Hanser).

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2010 "Integrated Resource Plan for Connecticut" (see below), June 2010.

2010 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 4, 2010. Presented to the Connecticut Energy Advisory Board January 8, 2010.

"Dynamic Pricing: Potential Wholesale Market Benefits in New York State," lead authors: Samuel Newell and Ahmad Faruqui at The Brattle Group, with contributors Michael Swider, Christopher Brown, Donna Pratt, Arvind Jaggi and Randy Bowers at the New York Independent System Operator, submitted as "Supplemental Comments of the NYISO Inc. on the Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure," in State of New York Public Service Commission Case 09-M-0074, December 17, 2009.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2009 "Integrated Resource Plan for Connecticut" (see below), June 30, 2009.

2009 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 1, 2009.

"Informational Filing of the Internal Market Monitoring Unit's Report Analyzing the Operations and Effectiveness of the Forward Capacity Market," prepared by Dave LaPlante and Hung-po Chao of ISO-NE with Sam Newell, Metin Celebi, and Attila Hajos of The Brattle Group, filed with FERC on June 5, 2009 under Docket No. ER09-1282-000.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2008 "Integrated Resource Plan for Connecticut" and "Supplemental Reports" (see below), September 22, 2008.

"Integrated Resource Plan for Connecticut," co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board; co-authored with M. Chupka, A. Faruqui, and D. Murphy, January 2, 2008. Supplemental Report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Department of Utility Control; co-authored with M. Chupka, August 1, 2008.

"Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs," whitepaper by Samuel A. Newell and Ahmad Faruqui filed by Pepco Holdings, Inc. with the Public Utility Commissions of Delaware (Docket No. 07-28, 9/27/2007), Maryland (Case No. 9111, filed 12/21/07), New Jersey (BPU Docket No. EO07110881, filed 11/19/07), and Washington, DC (Formal Case No. 1056, filed 10/1/07). Presented orally to the Public Utility Commission of Delaware, September 5, 2007.

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, "Planning Analysis of the Paddock-Rockdale Project," report by American Transmission Company re: transmission cost-benefit analysis, April 5, 2007 (with J.P. Pfeifenberger and others).

Prepared Supplemental Testimony on Behalf of the Michigan Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-718-000 et al., re: Financial Impact of ComEd's and AEP's RTO Choices, December 21, 2004 (with J. P. Pfeifenberger).

Prepared Direct and Answering Testimony on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, September 15, 2004 (with J.P. Pfeifenberger).

Declaration on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, August 13, 2004 (with J.P. Pfeifenberger).

PUBLICATIONS

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, white paper prepared for NextEra Energy Resources, October 23, 2017 (with M. Celebi, J. Chang, M. Chupka, and I. Shavel), available at http://www.brattle.com/system/publications/pdfs/000/005/530/original/Evaluation_of_the_DOE's_Proposed_Grid_Resiliency_Pricing_Rule.pdf?1509064658.

Near Term Reliability Auctions in the NEM: Lessons from International Jurisdictions. Prepared for the Australian Energy Market Operator, August 23, 2017 (with K. Spees, DL 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), available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Pricing_Carbon_into_NYISOs_Wholesale_Energy_Market.pdf

"How wholesale power markets and state environmental Policies can work together," *Utility Dive*, July 10, 2017 (with J. Pfeifenberger, J. Chang, and K. Spees), available at http://www.utilitydive.com/news/how-wholesale-power-markets-and-state-environmental-policies-can-work-toget/446715/

Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia, whitepaper prepared for the Public Utilities Office in the Government of Western 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).

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. Pefiefenberger, 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, 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, report prepared for PJM Interconnection LLC, August 26, 2011 (with J. Pfeifenberger, K. Spees, and others).

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 written for the NYISO and submitted to 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, whitepaper 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

"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," May 30, 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.

"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, February 26, 2018.

"NARUC Winter Policy Summit," presented to The Committee on Gas Panel on "Natural Gas Reliability: Understanding Fact from Fiction," 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, 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, September 30, 2014, Austin, TX.

"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, 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, 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 Jürgen 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, 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 electricity wholesale market design, transmission planning and development, renewable and climate policy analysis, and strategic planning for utility companies. 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 analyzed approaches to improving long-term transmission planning, including using scenario-based approaches in the Electric Reliability Council of Texas, considering a wider-range of benefits of transmission, and analyzing those benefits for a set of proposed transmission portfolios. In addition, Michael has focused on analyzing opportunities and challenges of existing and proposed renewable energy and climate policies, including the EPA's Clean Power Plan (CPP), state-level Renewable Portfolio Standards (RPS), and California's GHG cap-and-trade market.

Mr. Hagerty holds a B.S in Chemical Engineering from the University of Notre Dame in South Bend, Indiana and an M.S. in Technology and Policy from the Massachusetts Institute of Technology in Cambridge, Massachusetts.

Prior to joining The Brattle Group, Mr. Hagerty was a Research Assistant at the MIT Energy Initiative. Before that, he was a Chief Process Advisor for UOP/Honeywell.

AREAS OF EXPERTISE

- Electricity wholesale market design
- Renewable energy and climate policy analysis
- Transmission planning and development
- Strategic planning and long-term resource planning

EXPERIENCE

Electricity Wholesale Market Design

- **PJM Cost of New Entry Study.** For PJM in 2014 and 2018, 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 energy margins and ancillary services revenues in the Net CONE calculation and proposed revisions and a forward-looking approach.

- **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.

Renewable Energy and Climate Policy Analysis

- **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.

- **Regulatory Analysis of Renewable Fuel Standard**: For Growth Energy, analyzed and produced a report on the basis for EPA's proposed 2017 renewable volume obligations under the Renewable Fuel Standard program. The report examined the statistical analysis relating to the E85 fuel market that EPA cited in setting the standard, focusing on blender margins and flex-fuel vehicle owner fuel choice. Growth Energy included the report, Peeking Over the Blendwall: An Analysis of the Proposed 2017 Renewable Volume Obligations, July 11, 2016, to the Docket EPA-HQ-OAR-2016-0004
- **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.
- **Renewable Transportation Fuel (E85) Market Analysis**: For Butamax Advanced Biofuels Fuels LLC, supported Dr. Philip K. Verleger, Jr. in modeling the E85 fuel market demand, supply and D6 RIN prices necessary to attain various renewable volume obligations to support comments to the Environmental Protection Agency submitted January 28, 2014 to Docket EPA-HQ-OAR-2013-0479 – 2014 Standards for the Renewable Fuel Standard (RFS) Program.
- **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.

Transmission Planning and Development

- **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.

Strategic Planning and Long-term Resource Planning

- **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.

PUBLICATIONS

- "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

- "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.
- "Impacts of the Clean Power Plan: Moving From Design to Implementation and Compliance," Ethical Electric Annual Meeting, October 2015.
- "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.

October 10, 2018

Sang H. Gang
Principal Consultant & Project Manager
Sargent & Lundy Consulting

EDUCATION

University of Illinois at Urbana-Champaign—B.S. Electrical Engineering—2003

University of Illinois at Urbana-Champaign—Electrical Engineering Graduate Work, 2003–2006

REGISTRATIONS

Professional Engineer in Illinois

LANGUAGES

Bilingual Proficiency in English & Korean

EXPERTISE

- Project Management
- Power Project Development Support & Owner’s Engineering Services
- Power Project Due Diligence & Lender’s Advisory Services
- Utility-Scale Solar Photovoltaic Projects
- Grid Modernization / Smart Grid technologies
- Battery Energy Storage System & Micro-grid Projects
- Power Plant Grid Interconnection
- Renewable Energy Project Financing
- U.S. Electricity Markets
- Electrical System Analysis and Design
- Nuclear Plant Emergency Diesel Generators
- Nuclear Plant Modifications

RESPONSIBILITIES

As a Principal Consultant and a Project Manager within Sargent & Lundy’s Consulting Group, Mr. Gang is responsible for planning and managing a wide range of projects in the electric power industry. He provides support for project development, owner’s engineering, technical due diligence, independent engineering, construction monitoring, condition assessment, and technical advisory services for coal, gas, nuclear, and renewable, grid modernization, and transmission 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.

Mr. Gang is one of the Sargent & Lundy's subject matter specialists in battery energy storage, grid modernization, smart grid, and solar PV power technology. He has extensive experience with domestic and international utility-scale PV projects and a wide variety of PV technologies. His solar project expertise includes conceptual design, solar resource evaluation, energy yield assessment, probabilistic analysis, electrical design, reliability, O&M, project development, contracting strategy, and financial evaluation.

EXPERIENCE

UTILITY PLANNING PROJECTS

Confidential Client | 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.

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

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, US Steel Keystone Industrial Port Complex (KIPC) | 2013

Performed high-level condition assessment and valuation of the 30-MW KIPC electrical distribution system and developed cost optimization plan.

GAS, COIL, & OIL POWER PROJECTS

Confidential Client | 2018

Performed technical due diligence reviews of 2x300 MW coal plant in operation and 2x660MW coal plant under construction, in support of potential asset acquisition.

Confidential Client | 2017

Performed technical due diligence reviews of 16 coal and gas fired power plants in Canada, U.S., and Australia, in support of potential asset acquisition.

Confidential Client | 2017

Performed technical due diligence reviews of Norte-III combined-cycle power project in Mexico, in support of potential asset acquisition.

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., Mariveles Coal Power Station

- 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. (2016)

Sithe Global, Mariveles Coal Power Station | 2015–2016

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., Az-Zour North (AZN) Phase 1 Independent Water and Power Project | 2016

Project Manager for on-line audit of the Plant Accounting Settlement System and Fuel Demand Model.

Mirfa International Power & Water Company, Mirfa Independent Water and Power Project | 2015–2016

Project Manager for off-line audit of the Plant Accounting Settlement System, Fuel Demand Model, and Outage Mode Model.

Confidential Client | 2016

Performed technical due-diligence review of four-unit, 2,400-MW coal-fired power plant in U.A.E. for potential lenders.

Venture Global LNG, Calcasieu Pass LNG Export Facility | 2015–2016

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 in Louisiana.

Confidential Client | 2015

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 in Mexico.

Siddiqsons Energy | 2015

Performed feasibility study and prepared technical specifications for developing a 350-MW supercritical coal-fired power plant in Karachi, Pakistan.

SK Engineering & Construction (SK E&C), Jangmoon Combined Cycle Power Plant | 2014

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 in South Korea.

Korea Sothern Power Company (KOSPO), Kelar Combined Cycle Power Plant | 2014

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), Jeddah South Thermal Power Plant Stage 1 | 2013–2014

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 in Saudi Arabia.

Confidential Client | 2013

Performed technical due-diligence review of a two-unit, 834-MW combined cycle power project in Israel for a potential lender.

RENEWABLE ENERGY PROJECTS

Confidential Client | 2018

Owner's engineer for a new 100-MW solar PV project in Mexico. Supported EPC and O&M contract negotiations and preliminary site and technology evaluations.

Confidential Client | 2018

Prepared CAISO interconnection applications and supplemental technical requirements for 100+ MW solar PV + battery energy storage projects.

Confidential Client | 2018

Prepared MISO interconnection application and supplemental technical requirements for 100+-MW solar PV project.

Confidential Client | 2018

Performed GIS-based site identification study for multiple small utility-scale solar PV projects throughout the state of Michigan.

Confidential Client | 2017

Performed technical due diligence review of two 60-MW biomass projects in Georgia for potential asset acquisition.

Confidential Client | 2016

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 in central U.S.

Confidential Client | 2016

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 in central U.S.

Confidential Client | 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.

Confidential Client | 2016

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

Performed technical due diligence of a 100-MW single-axis tracking solar PV project in northern Chile.

Overseas Private Investment Corporation, Real El Salvador Solar PV Project | 2015

Performed independent energy yield assessments to support financing of a portfolio of eight solar PV projects in El Salvador.

Electric Power Research Institute (EPRI)

- Developed utility-scale performance and financial models of various PV technologies to update the EPRI Report, “Solar Energy Technology Guide - 3002001638.” (2014 & 2015)

- 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.” (2013)

NextEra Energy Resources, Javelina Wind Project | 2015

Performed Independent Engineering balance-of-plant reviews of a 250-MW wind project in Texas.

TerraForm Power | 2015

Performed technical due diligence to support asset acquisition of two 10-MW solar PV projects in Ontario, Canada.

International Finance Corporation, San Carlos Solar PV Projects

- 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— in the Philippines. (2014)
- Performed operations monitoring of the three projects (2015)

Overseas Private Investment Corporation, Content Solar PV Project | 2015

Performed pre-construction technical due diligence of a 22-MW solar PV project in Jamaica.

Overseas Private Investment Corporation, Confidential Wind Project | 2014

Performed Independent Engineering review of wind resource and energy yield assessment for a 50-MW wind project in Pakistan.

Macquarie Capital, Simon Solar PV Project | 2013

Performed lender’s technical due diligence review of a 30-MW solar PV project in Georgia.

Overseas Private Investment Corporation, Confidential Solar PV Project | 2013

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 in Tanzania.

Standard Bank of South Africa, Beaufort West PV Project | 2013

Performed Independent Engineering review of projected energy yield model of a 60-MW solar PV project in South Africa.

NextEra Energy Resources, Red River Portfolio | 2013

Performed Independent Engineering balance-of-plant reviews and compliance review of interconnection requirements of two commercially operating wind farms in Texas (255 MW total) to support re-financing.

NextEra Energy Resources, Steele Flats Wind Project | 2013

Performed Independent Engineering balance-of-plant reviews of a 75-MW wind project in Nebraska.

Standard Bank of South Africa, MetroWind Project | 2013

Performed Independent Engineering review of construction progress of a 27-MW wind project in South Africa.

NUCLEAR POWER PROJECTS

Nawah Energy Company, Barakah Nuclear Power Plant | 2018

Performed off-line audit of the Plant Accounting Settlement System.

Korea Hydro & Nuclear Power (KHNP) | 2016–2018

Project Manager for classroom training program consisting of 20 different technical subject courses in nuclear power plant design and analysis.

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, Barakah Nuclear Power Plant Units 1 & 2 | 2014

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 & 2 engineering design.

Tennessee Valley Authority (TVA), Browns Ferry Nuclear Plant

- Emergency Diesel Generator Governor Upgrade (2009–2013)
- NFPA-805: EECW System Circuit Modification (2012–2013)
- NFPA-805: Emergency Diesel Generator Protective Relay Circuit Modification (2012)
- LPCI MG Set Abandonment (2012)
- Service Building Transformer Replacement (2010–2011)
- Generator Voltage Regulator Replacement (2010–2012)
- Low Voltage Circuit Breakers Replacement (2008–2012)
- Emergency Diesel Generator Turbocharger Lube Oil System Modification (2008–2012)

Exhibit No. 2

2018 CONE Study

PJM Cost of New Entry

Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date

PREPARED FOR

PJM Interconnection, L.L.C.

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April 19, 2018

THE Brattle GROUP

This report was prepared for PJM Interconnection, L.L.C. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or Sargent & Lundy, or their clients.

The authors would like to thank PJM staff for their cooperation and responsiveness to our many questions and requests. We would also like to thank the PJM Independent Market Monitor for helpful discussions.

Table of Contents

Executive Summary

PJM Interconnection, L.L.C (PJM) retained 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.[1] This report presents our estimates of the Cost of New Entry (CONE). A separate, concurrently-released report presents our review of PJM's methodology for estimating the net energy and ancillary service (E&AS) revenue offset and the Variable Resource Requirement (VRR) curve.[2]

CONE represents the total annual net revenue (net of variable operating costs) that a new generation resource would need to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. CONE is the starting point for estimating the Net Cost of New Entry (Net CONE). Net CONE represents the first-year revenues that a new resource would need to earn in the capacity market, after netting out E&AS margins from CONE. CONE and Net CONE of the simple-cycle combustion turbine (CT) reference resource are used to set the prices on PJM's VRR curve.[3] CT and combined-cycle (CC) Net CONE are used to establish offer price thresholds below which new gas-fired generation offers are reviewed under the Minimum Offer Price Rule (MOPR).[4]

We estimate CONE for CTs and CCs in each of the four CONE Areas specified in the PJM Tariff, with an assumed online date of June 1, 2022.[5] Our estimates are based on complete plant designs reflecting the locations, technology choices, and plant configurations that developers are likely to choose, as indicated by actual projects and current environmental requirements. For both the CT and CC plants, we specify GE 7HA turbines—one for the CT, and two for the CC in combination with a single heat recovery steam generator and steam turbine ("2×1 configuration"). Most plants have selective catalytic reduction (SCR), except CTs in the Rest of RTO Area. Most plants also have dual-fuel capability, except CCs in the SWMAAC Area, which obtain firm gas transportation service instead.

For each plant type and location, we conduct 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

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1 PJM Interconnection, L.L.C. (2017). PJM Open Access Transmission Tariff. Effective October 1, 2017, ("PJM 2017 OATT"), accessed 2/7/2018 from http://www.pjm.com/directory/merged-tariffs/oatt.pdf, Section 5.10 a.

2 "Fourth Quadrennial Review of PJM's Variable Resource Requirement Curve" or "2018 VRR Report".

3 See 2018 VRR Report for how CONE and Net CONE values are used to set the VRR curve.

4 PJM 2017 OATT, Section 5.14 h.

5 Previous CONE studies had five CONE Areas, but the Dominion CONE Area was removed in recent tariff changes and is now included in the Rest of RTO CONE Area.

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.

Finally, we translate the estimated costs into the annualized average net revenues the resource owner would have to earn over an assumed 20-year economic life to achieve its required return on and return of capital. We assume an after-tax weighted-average cost of capital (ATWACC) of 7.5% for a merchant generation investment, which we estimated based on various reference points. An ATWACC of 7.5% is equivalent to a return on equity of 12.8%, a 6.5% cost of debt, and a 65/35 debt-to-equity capital structure with an effective combined state and federal tax rate of 29.25%. For some states with higher state income tax rates of 10%, the ATWACC is 7.4%. We adopt the "level-nominal" approach for calculating the first-year annualized costs of the plants.

Table ES-1 below shows the updated 2022/23 CONE estimates and how the values compare to the CONE parameters used in the upcoming auctions for the 2021/22 delivery year, escalated forward one year to 2022/23. As indicated, costs have decreased sharply by 22–28% for CTs and 40–41% for CCs.

Table ES-1: Updated 2022/2023 CONE Values

	Simple Cycle ($/ICAP MW-year)				Combined Cycle ($/ICAP MW-year)			
	EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
2021/22 Auction Parameter	$133,144	$140,953	$133,016	$134,124	$186,807	$193,562	$178,958	$185,418
...Escalated to 2022/23	$136,900	$144,900	$136,700	$137,900	$192,000	$199,000	$184,000	$190,600
Updated 2022/23 CONE	**$106,400**	**$108,400**	**$98,200**	**$103,800**	**$116,000**	**$120,200**	**$109,800**	**$111,800**
Difference from Prior CONE	-22%	-25%	-28%	-25%	-40%	-40%	-40%	-41%

Sources and notes:

All monetary values are presented in nominal dollars.

2021/22 auction parameter values based on Minimum Offer Price Rule (MOPR) Floor Offer Prices for 2021/22 BRA.

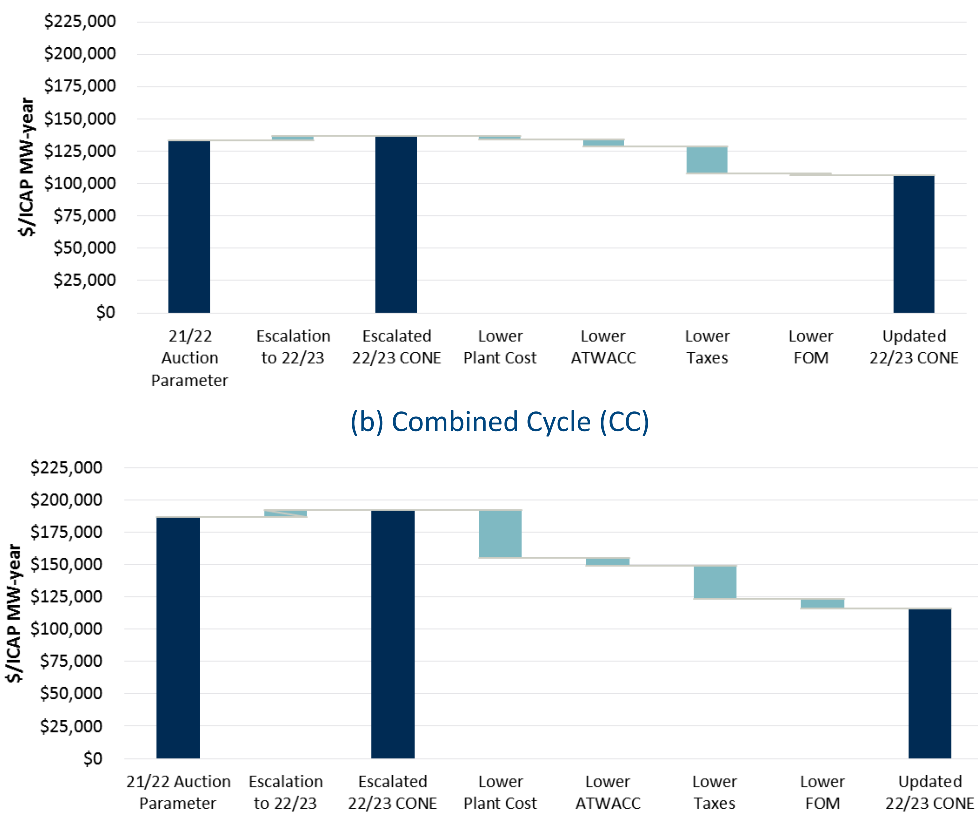
PJM 2021/22 parameters escalated to 2022/23 by 2.8%, based on S&L analysis of escalation rates for materials, turbine, and labor costs.

CONE includes major maintenance costs in variable O&M costs. Alternative values with major maintenance costs in fixed O&M costs are presented in Appendix C.

The drivers of these decreases are shown in Figure ES-1 and explained below.

Figure ES-1: Drivers of Lower CT and CC 2022/2023 CONE Estimates (EMAAC)

(a) Simple Cycle Combustion Turbine (CT)



Notes:
"FOM" stands for fixed O&M costs.
CONE includes major maintenance in variable O&M costs.

Three factors drive most of this decrease in CONE:

- **Economies of scale on larger combustion turbines.** Selection of GE 7HA.02 turbines instead of the 7FA.05 turbines used in the 2014 PJM CONE study reflects a recent trend in actual project developments and future orders toward larger turbines. The GE H-class turbines are sized at 320 MW per turbine compared to 190 MW for F-class turbines in 2014; the capacity of a 2×1 CC plant nearly doubles from 650 to 1,140 MW.[6] This lowers both construction labor and equipment costs on a per-kW basis. As a result, the current overnight capital costs for a CT are only $799/kW to $898/kW (depending on location), 2–10% lower than the 2014 estimates of $890/kW to $927/kW escalated forward to 2022.[7]

[6] The max summer capacity is based on the estimated values for the Rest of RTO CONE Area.

[7] We compare the current capital cost estimates to those filed by PJM in the 2014 CONE update. We escalated the 2018 capital costs to 2022 by first applying the location-specific escalation rates PJM used for the 2019/20, 2020/21, and 2021/22 CONE updates for the first three years and then escalating the costs an additional year by 2.8%/year based on cost trends in labor, equipment, and materials inputs.

CC capital costs range from $772/kW to $873/kW, about 25% lower than the 2014 estimates of $1,054/kW to $1,127/kW escalated to 2022.

- **Reduced federal taxes.** The tax law passed in December 2017 reduced the corporate tax rate to 21% and temporarily increased bonus depreciation to 100%, although it eliminated the state income tax deduction.[8] These changes decrease the CT CONE by about $21,000/MW-year (17% lower) and the CC CONE by about $25,000/MW-year (18% lower), before accounting for the higher cost of capital due to the lower tax rate.
- **Lower cost of capital.** We estimate an ATWACC of 7.5% for merchant generation based on current and projected capital market conditions and the change in the corporate tax rate. Compared to an ATWACC of 8.0% in the 2014 study, the lower ATWACC reduces the annual CONE value by 3.7% for CTs and 3.8% CCs.

The updated CONE values shown above assume that major maintenance costs are treated as variable O&M costs, as in past CONE studies. We separately report in Appendix C alternative CONE values to reflect changes in the PJM cost guidelines since the 2014 CONE Study in which major maintenance costs are classified as fixed O&M costs instead of variable O&M costs.[9] Classifying these costs as fixed instead of variable increases CONE by $19,000/MW-year for CTs (a 19% increase) and $10,000/MW-year for CCs (a 9% increase). However, removing these costs from variable O&M increases Net E&AS revenues and offsets the increased CONE value in the calculation of Net CONE.

Table ES-2 shows additional details on the CONE estimates for CT plants in each CONE Area. The higher CONE in SWMAAC relative to other areas reflects higher property taxes in Maryland that are based on all property, including equipment, not just land and buildings. EMAAC's relatively high costs reflect higher labor costs there. The Rest of RTO Area has the lowest CONE value due to lower labor costs and the assumption that an SCR is not needed to reduce NOx emissions in attainment areas.

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8 "Bonus depreciation" refers to the allowance by tax law of highly accelerated tax depreciation immediately upon in-service of a depreciable asset. In recent years, bonus depreciation has been enabled by legislation in varying percentages of the overall tax basis in an asset, with the remainder deducted over the asset life as otherwise allowed. Per the 2017 tax law, bonus depreciation is allowed for companies not classified as public utilities up to 100% of tax basis.

9 An ongoing stakeholder process within the Markets Implementation Committee is addressing whether the PJM cost guidelines should be modified to again allow major maintenance costs to be included in variable O&M costs.

Table ES-2: Estimated CT CONE for 2022/2023

		Simple Cycle			
		EMAAC	SWMAAC	Rest of RTO	WMAAC
Net Summer ICAP	*MW*	352	355	321	344
Overnight Costs	*$/kW*	$898	$836	$799	$886
Effective Charge Rate	*%*	10.1%	10.1%	10.0%	10.0%
Plant Costs	*$/MW-yr*	$90,300	$84,300	$80,300	$88,900
Fixed O&M	*$/MW-yr*	$16,100	$24,100	$17,900	$14,900
Levelized CONE	***$/MW-yr***	**$106,400**	**$108,400**	**$98,200**	**$103,800**
Levelized CONE	***$/MW-day***	**$292**	**$297**	**$269**	**$284**

Notes: CONE values expressed in 2022 dollars and Installed Capacity (ICAP) terms.

Table ES-3 shows the recommended CONE estimates for CC plants in each CONE Area. SWMAAC has the highest CONE estimate due to higher property taxes and the higher costs of firm gas transportation service compared to dual-fuel capabilities (which is specified in the other Areas). EMAAC has the next highest CONE estimate due to higher labor costs than the rest of PJM. WMAAC and Rest of RTO have the lowest CC CONE estimates due to the lower labor costs in those areas.

Table ES-3: Estimated CC CONE for 2022/2023

		Combined Cycle			
		EMAAC	SWMAAC	Rest of RTO	WMAAC
Net Summer ICAP	*MW*	1,152	1,160	1,138	1,126
Overnight Costs	*$/kW*	$873	$772	$815	$853
Effective Charge Rate	*%*	10.6%	10.6%	10.5%	10.5%
Plant Costs	*$/MW-yr*	$92,200	$81,800	$85,900	$89,900
Fixed O&M	*$/MW-yr*	$23,800	$38,400	$23,900	$21,900
Levelized CONE	***$/MW-yr***	**$116,000**	**$120,200**	**$109,800**	**$111,800**
Levelized CONE	***$/MW-day***	**$318**	**$329**	**$301**	**$306**

Notes: CONE values expressed in 2022 dollars and ICAP terms.

The updated CONE estimates for CCs have decreased significantly more than CTs over the prior estimates, leading to a CC premium of $8,000–11,800/MW-year compared to $46,000–54,000/MW-year in the 2020/21 Base Residual Auction (BRA) parameters. The most significant driver narrowing the difference between CT and CC CONE is economies of scale of the larger CC based on the 7HA. While the capacity of the CCs plants has almost *doubled* compared to that in the 2014 CONE Study, the cost of the gas turbines increased by 50%, and the cost of the steam section of the CC (including the heat recovery steam generator and steam turbine) increased by only 30%. CT plants share the same economies of scale on the combustion turbine itself, but not the greater economies of scale that CCs enjoy on their steam section or other plant costs.

Looking beyond the 2022/23 delivery year, we recommend that PJM update the above CONE estimates prior to each subsequent auction using its existing annual updating approach based on a composite of cost indices, but with slight adjustments to the weightings. Consistent with the updated capital cost estimates, we recommend that PJM weight the components in the CT composite index based on 20% labor, 55% materials (increased from 50%), and 25% turbine (decreased from 30%). We recommend that PJM weight the CC components based on 30% labor (increased from 25%), 50% materials (decreased from 60%), and 20% turbine (increased from 15%). PJM will need to account for bonus depreciation declining by 20% in subsequent years starting in 2023. Consequently, after PJM has escalated CONE by the composite cost index, we recommend that PJM apply an additional gross-up of 1.022 for CT and 1.025 for CCs each year to account for the declining tax advantages as bonus depreciation phases out.

I. Introduction

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." The VRR curve is determined administratively based on a design objective to procure sufficient capacity for maintaining resource adequacy in all locations while mitigating price volatility and susceptibility to market power abuse. As such, the VRR curves are centered approximately on a target point with a price given by the estimated Net Cost of New Entry (Net CONE) and a quantity corresponding to PJM's resource adequacy requirement. The curve's slope mitigates price volatility, and a slight right shift (relative to the target point) avoids low reliability outcomes.

In order for the VRR curve to procure sufficient capacity, the Net CONE parameter must accurately reflect the price at which developers would actually be willing to enter the market. Estimated Net CONE should reflect the first-year capacity revenue an economically-efficient new generation resource would need (in combination with expected energy and ancillary services (E&AS) margins) to recover its capital and fixed costs, given reasonable expectations about future cost recovery under continued equilibrium conditions. PJM estimates Net CONE for a defined "reference resource" by subtracting its estimated one-year E&AS margins from its estimated Cost of New Entry (CONE).

CONE values are determined through quadrennial CONE studies such as this one, with escalation rates applied in the intervening years.[10] PJM separately estimates Net E&AS revenue offsets annually for setting the zone-specific Net CONE values in each auction. Just prior to each three-year forward auction, PJM determines Net CONE values for each of four CONE Areas, which are used to establish VRR curves for the system and for all Locational Deliverability Areas (LDAs).[11]

PJM has traditionally estimated CONE and Net CONE based on a gas-fired simple-cycle combustion turbine (CT) as the reference resource. In addition to anchoring the VRR curve, PJM uses CONE estimates for CT and combined-cycle (CC) plants for calculating offer price screens under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[12]

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10 PJM 2017 OATT, Section 5.10 a.

11 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.

12 PJM 2017 OATT, Section 5.14 h.

B. Study Objective and Scope

We were asked to assist PJM and stakeholders in this quadrennial review by developing CONE estimates for new CT and CC plants in each of the four CONE Areas for the 2022/23 Base Residual Auction (BRA) and proposing a process to update these estimates for the following three BRAs.

Our objective in estimating CONE is to reflect the technology, 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 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 tradeoffs and provide our own recommendations for best meeting RPM's objectives to inform PJM's decisions in setting future VRR curves.

We review PJM's methodology for estimating the Net E&AS revenue offsets for each reference resource and the criteria for selecting the reference resource in the parallel 2018 VRR Curve Report.

C. Analytical Approach

Our starting point for estimating CONE is a characterization of the CC and CT plants in each CONE Area to reflect the technologies, plant configurations, detailed specifications, and locations where developers are most likely to build. While the turbine technology and other specifications for the reference resource are detailed in PJM's tariff, we review the most recent gas-fired generation projects in PJM and the U.S. to determine whether these assumptions remain relevant to the PJM market.[13] The key configuration variables we define for each plant include the number of gas and steam turbines, duct firing and power augmentation, cooling systems, emissions controls, and dual-fuel capability.

We identified specific plant 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. We selected key site characteristics, which include proximity to high voltage transmission infrastructure and interstate gas pipelines, siting attractiveness as indicated by units recently built or currently under construction, and availability of vacant industrial land. Our analysis for selecting plant characteristics and locations for each CONE Area is presented in Section III of this report.

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13 PJM 2017 OATT.

We developed comprehensive, bottom-up estimates of the costs of building and maintaining the candidate references resources in each of the four CONE Areas. 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. The results of this analysis are presented in Section IV.

We further estimated annual fixed and variable O&M costs, including labor, materials, property tax, insurance, asset management costs, and working capital. The results of this analysis are presented in Section V.

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. We present our financial assumptions for converting the costs of building and operating the plant into an annualized CONE estimate in Section VI and a summary of the CONE estimates in Section VII.

The Brattle and Sargent & Lundy authors collaborated on completing 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.

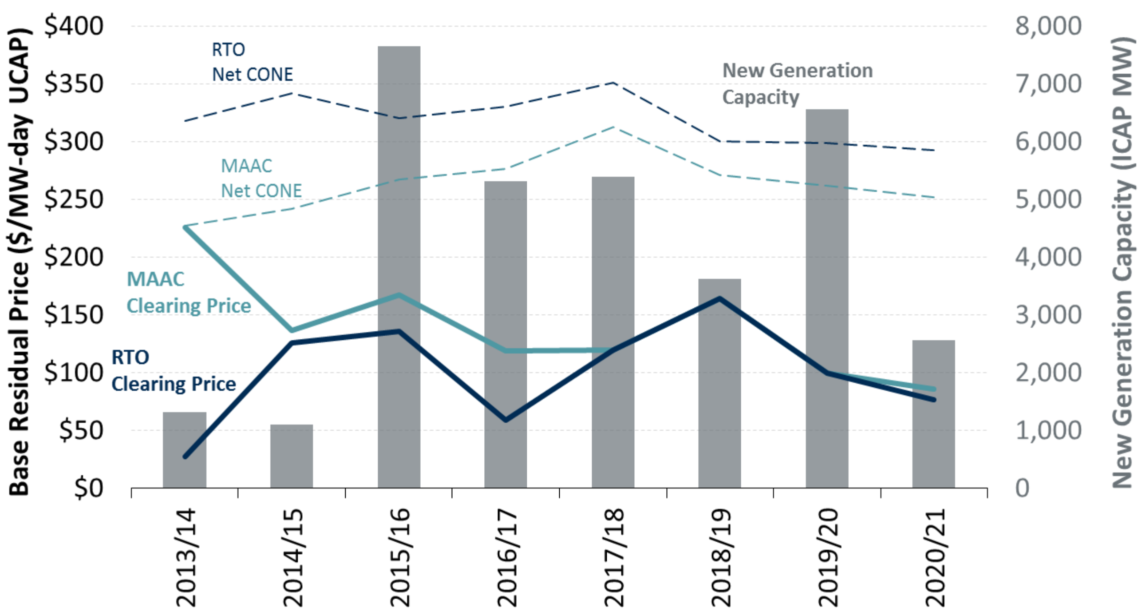
II. Observations about Recent Entry in PJM's Capacity Market

As a starting point for our analysis of the Net Cost of New Entry, we reviewed the recent market activity to better understand the underlying dynamics in the PJM Base Residual Auctions and identify areas of focus for the current Net CONE study.

A. Summary of Recent New Entry in PJM

Over 31,000 ICAP MW of new generation resources cleared the market in the six auctions since the 2015/16 Base Residual Auction (BRA) despite the auctions clearing well below the administratively-determined Net CONE parameter. Figure 1 below shows that, on average, these auctions have cleared at prices 60% below the Net CONE parameter during this period of significant entry of new generation resources.[14] As the clearing prices reflect the offer price of the marginal unit clearing the market, new generation resources must have on average been submitting offers into the auction at even lower prices.

Figure 1: Base Residual Auction Clearing Prices and Cleared New Generation Capacity



Sources and notes:
PJM Annual Base Residual Auction Results, accessed September 2017, http://www.pjm.com/markets-and-operations/rpm.aspx

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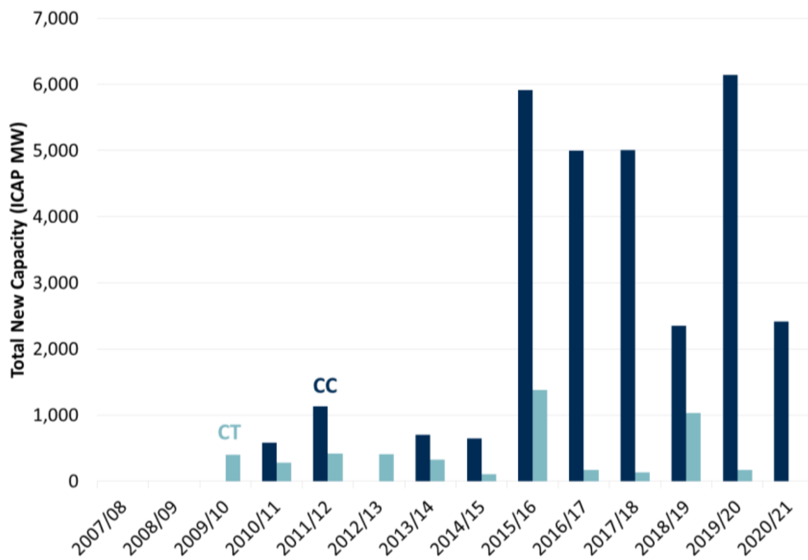
[14] Some new generation capacity has cleared in sub-zones at higher prices than shown in Figure 1. However, most of the new capacity that has cleared during this time period did so at the prices shown here.

About half of new generation capacity since the 2015/16 BRA cleared in MAAC and the other half cleared in the rest of the PJM system.[15] A third of the new plants are CCs located close to shale gas production regions in Pennsylvania and Ohio to take advantage of pipeline constraints that result in lower local gas prices relative to the rest of PJM.[16] The remaining plants are located throughout the PJM market with significant additions in Virginia, New Jersey, and the western portions of PJM.

Nearly all new generating units entering the BRAs are natural-gas-fired. Most of these new natural gas plants consist of CC plants, as shown in Figure 2 below, while the Net CONE parameter is currently set based on a CT. There were significant additions of new CTs in PJM prior to 2005, but limited merchant entry since then.[17] While CCs went through a similar lull in new additions between 2005 and 2014—when the PJM capacity market attracted other resource types, such as uprates to existing plants, deferred retirement, imports, and demand response—a total of 27,000 MW of new CC plants have cleared since the 2015/16 BRA.

Figure 2: CC and CT Generation Capacity Cleared in Past BRAs



Sources and notes:
PJM Base Residual Auction Results for 2020/21, published on 5/23/2017.

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15 Based on the PJM Annual Base Residual Auction Results, there has been 12,800 Unforced Capacity (UCAP) MW of new capacity in MAAC since the 2015/16 BRA and 13,000 UCAP MW of new capacity in the rest of the PJM system. PJM Annual Base Residual Auction Results, accessed September 2017, http://www.pjm.com/markets-and-operations/rpm.aspx

16 We identified plants with access to lower-cost natural gas based on the gas hub listed for each plant in ABB Inc.'s *Energy Velocity Suite*. We considered plants with access to gas priced based on the Dominion South, Dominion North, Leidy Hub, Transco Leidy Receipts, or Tennessee Gas Pipeline Zone 4 as within shale production regions.

17 There has been entry of just two merchant CTs since 2014 (340 MW Doswell Peaking Unit and 141 MW Perryman Unit 6).

B. Drivers of Low-Cost Entry by Natural Gas Plants

Several factors have led to the significant investment in new gas-fired CC plants at capacity market prices that have been on average 60% below PJM's Net CONE value during the past six BRAs. Coal and nuclear retirements and the exit of some demand response resources created the need for new entry. We believe that the entry by CC plants was possible at the observed low prices in large part due to improved combustion turbine performance, lower plant cost on a $/kW basis, low-cost investment capital, and low natural gas prices (allowing for large spark spreads) in some locations.

Generation Retirements: There has been a surge of generation retirements in PJM since 2011 with 32,800 MW of existing resourcing deactivating or requesting deactivations over the ten-year period from 2011 to 2020 (compared to just 6,600 MW from 2002 to 2010).[18] The majority of these retirements have been coal plants (26,000 MW) while several nuclear plants (3,200 MW) have announced retirements by 2020.[19] Even during a period of limited load growth, the retirements provided an opportunity for new generation resources to enter the market.[20] The retirements help explain the scale of recent new entry, but not the low prices at which entry has occurred. We next examine several factors that contribute to new gas CCs entering the capacity auctions at prices below the estimated Net CONE.

Turbine Performance: The efficiency and net plant capacity of gas turbines has risen significantly since 2010. As shown in Figure 3 below, CC plants with GE 7FA turbines in a 2×1 configuration (2 gas turbines, 1 steam turbine) have increased their net plant capacity since 2008 by 220 MW (a 42% increase), while reducing their net plant heat rate (HHV) by 440 Btu/kWh from 6,780 to 6,340 Btu/kWh (a 6% decrease).[21] This trend in performance is significant even before accounting for the introduction of the larger, more efficient H-class turbines that are now beginning to enter the market (see Section III.B below). The H-class turbines provide a step change in terms of the economies of scale: a 2×1 CC configuration with H-class turbines achieves a net plant output of about 1,100 MW and a net heat rate (HHV) of nearly 6,100 Btu/kWh.[22] The larger turbines result in significant cost savings on a per-kW basis due to the economies of scale for developing such large plants. The improved efficiency of these turbines increases the Net

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18 PJM. Generator Deactivation Summary Sheets, accessed December 2017, http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx

19 ABB Inc.'s *Energy Velocity Suite* December 2017.

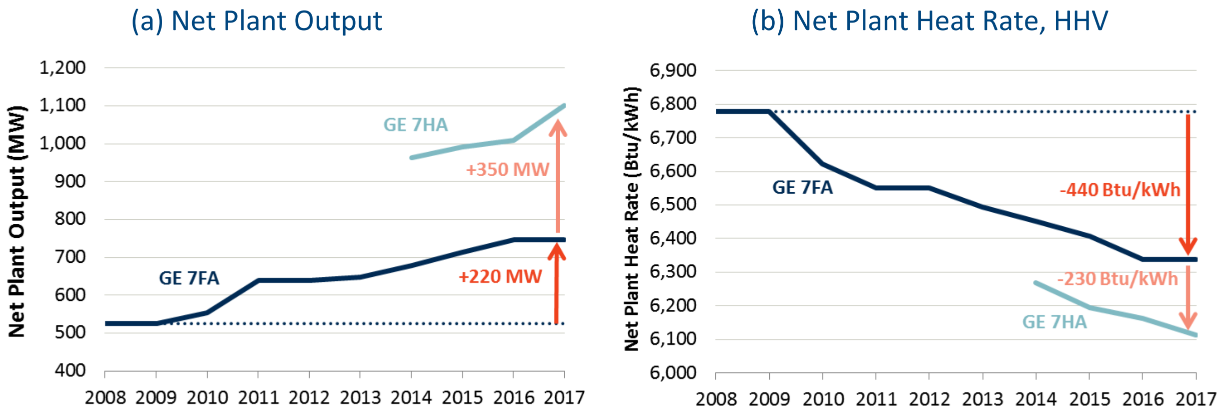
20 The Reliability Requirement (adjusted for FRR) grew by just 6,000 MW (4%) from the 2014/15 BRA (148,323 MW) to the 2020/21 BRA (154,355 MW). Annual BRA parameters available here: http://www.pjm.com/markets-and-operations/rpm.aspx

21 Gas Turbine World, "2016–17 GTW Handbook," Volume 32.

22 The net heat rate reported here is lower than estimated for each CONE Area due to the conditions under which the heat rate is estimated (ISO conditions of 59°F, 60% Relative Humidity and 0 feet above mean sea level).

E&AS revenue offset for the new gas plants by reducing their dispatch costs and increasing the frequency with which they operate. Both trends result in reduced offers into the PJM capacity auctions.

Figure 3: Historical Performance of GE 7FA and GE 7HA in a 2×1 Combined-Cycle Configuration



Sources and notes:
Gas Turbine World, "2016–17 GTW Handbook," Volume 32.

Turbine Costs: The increase in net plant capacity since 2008 for CTs has occurred during a period of relatively limited cost increases for the turbines and the overall plants. The result is a significantly lower cost for gas-fired combustion turbines on a per-kW basis, whether in simple-cycle or combined-cycle configurations. The per-kW costs for combustion turbines have declined by nearly 40% since they peaked in 2010 and by 11% since 2014 (see Section VII.A for a further discussion of these trends). Similarly, the composite index that PJM uses to annually adjust the CT CONE value based on the Department of Commerce's Bureau of Labor Statistics (BLS) indices has decreased by 17% since 2010 when adjusted for the increased capacity of new CTs over this time period.[23] The declining cost for new turbines and plants on a per-kW basis result in a decline in the CONE for new gas plants.

Financing Cost: Financial drivers have contributed to reducing the price at which offers are placed into the PJM capacity auctions. The financing cost (cost of capital) for merchant generators has declined in recent years with the estimated after-tax weighted-average cost of capital (ATWACC) for publicly-traded merchant developers declining from 8.0% in 2014 to the current value of 7.5% as estimated in this study. Additional cost of capital reference points we identified based on analyst reports of recent acquisitions (as explained in detail in Section VI.A below) show the cost of capital may have been even lower in recent years.[24] A reduction in the cost of capital from 8.0% to 7.5% reduces CONE by about 3.8%. In addition, bonus depreciation

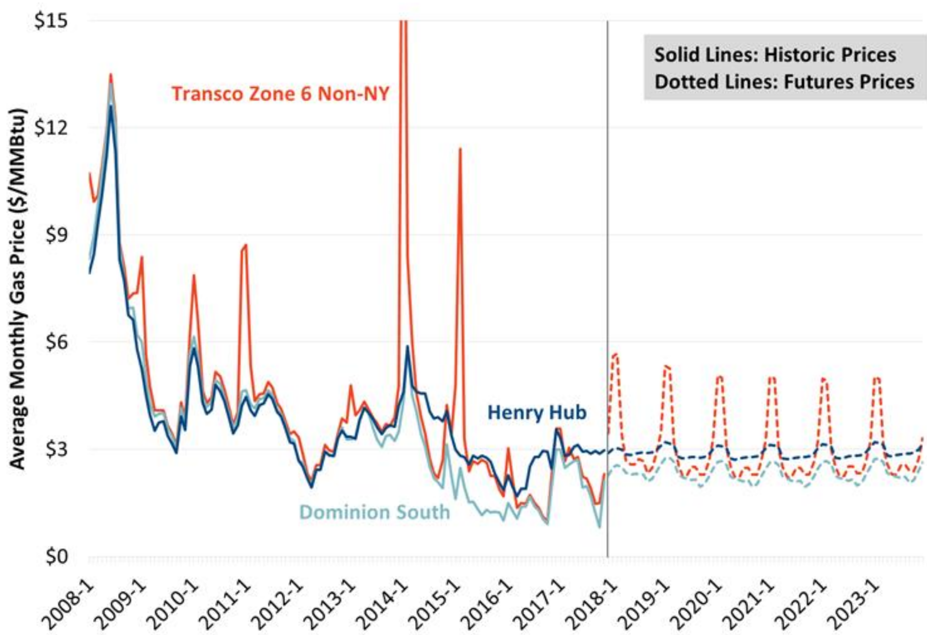
[23] The composite gas plant index that PJM uses blends BLS indices for turbine cost (30%), material costs (50%), and labor costs (20%). We discuss PJM's approach to annual updates to CONE based on these indices in Section VIII. below.

[24] For example, the June 2017 fairness opinion for the Calpine acquisition by Energy Capital Partners assumed 5.75% to 6.25% for Calpine's weighted-average cost of capital.

was available for the most recent new plants at the time of the auctions they cleared—with plants online by the end of 2017 able to depreciate 50% of their costs in the first year, 40% for plants online in 2018, and 30% for plants online in 2019.[25] We estimate that 30% bonus depreciation reduces CONE by about 3.5%.

Natural Gas Prices: The coal and nuclear plant retirements and entry of new gas CCs has been triggered by sustained low prices for natural gas. Shale gas production from the Marcellus and Utica formations that lie within the PJM market footprint increased significantly since 2010, resulting in lower gas prices across PJM and the U.S. as shown in Figure 4.[26] Gas prices in shale production regions, as represented below by the Dominion South hub (light blue line), have sold at a discount of $1–2/MMBtu to Henry Hub since 2014. Lower gas prices have extended to the eastern portions of PJM, as represented by the Transco Zone 6 Non-NY hub (red line), during three of the past four summers as well. Based on traded natural gas futures, Dominion South gas prices are expected to remain on average around $2.50/MMBtu through 2022, nearly $0.50/MMBtu lower than Henry Hub (dark blue line), based on current gas futures.

Figure 4: Gas Prices at Representative Gas Hubs in PJM



Sources and notes:
Historical prices downloaded from ABB Inc.'s *Energy Velocity Suite* and futures prices from SNL in December 2017.

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25 Bonus depreciation was re-introduced as a part of the changes to federal taxes in December 2017, starting at 100% for plants online by January 1, 2023 and then phasing out over the following five years. We discuss the implications of the bonus depreciation for new resources in Section VI.B below.

26 U.S. Energy Information Administration, 2010–2015. "U.S. Shale Gas Production", accessed December 2017 at https://www.eia.gov/dnav/ng/ng_prod_shalegas_s1_a.htm.

Lower gas prices reduce the fuel costs for new gas CCs relative to other fossil-fuel-fired plants that may determine PJM wholesale energy market prices—primarily coal plants—and result in higher annual output from these plants.[27] Lower gas prices will reduce average energy market prices and *net* revenues across all generation resources. Whether lower gas prices result in higher or lower net revenues for the new CCs will depend on the relative heat rate of the new gas plants compared to the market heat rate as set by generating units that tend to be on the margin for most of the year. Plants that enjoy a unique advantage in shale-gas locations are likely to earn higher net revenues as electricity market prices will be set by resources that must pay a higher price for delivered fuel, increasing the spread between revenues and costs for the CCs located in these shale-gas-regions.

We reviewed these recent market trends to understand what is driving the significant development of new gas-fired units at prices well below those projected in previous CONE studies and incorporated these trends into our analysis in the remainder of this report.

[27] Coal has been on the margin in PJM for 45–60% of hours since 2012. PJM, 2012–2016 CO_2, SO_2 and NO_X Emission Rates, March 17, 2017, p. 3. Available at: https://www.pjm.com/~/media/library/reports-notices/special-reports/20170317-2016-emissions-report.ashx

III. Reference Resource Technical Specifications

Similar to the 2014 PJM CONE Study, we determined the characteristics of the reference resources primarily based on a "revealed preferences" approach that relies on our review of the choices that actual developers found to be most feasible and economic. 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 selecting the reference resource location within each CONE Area, we relied on a similar analysis for the 2014 PJM CONE Study that considers a broad view of potential sites that can be considered feasible and favorable for new plant development. For determining most of the reference resource specifications, we updated our analysis from the 2014 study by examining CT and CC plants built in PJM and the U.S. since 2014, including plants currently under construction. We characterized these plants by size, plant configuration, turbine type, duct firing, environmental controls, dual-fuel capability, and cooling system.

A. Locational Screen

The PJM Open Access Transmission Tariff (OATT) requires a separate CONE parameter in each of four CONE Areas as summarized in Table 1.[28]

Table 1: PJM CONE Areas

	CONE Area	Transmission Zone	States
1	**EMAAC**	AECO, DPL, JCPL, PECO, PSEG, RECO	NJ, MD, PA, DE
2	**SWMAAC**	BGE, PEPCO	MD, DC
3	**Rest of RTO**	AEP, APS, ATSI, ComEd, DAY, DEOK, DQL, DOM	WV, VA, NC, OH, IN, IL, KY, TN, MI, PA, MD
4	**WMAAC**	MetEd, Penelec, PPL	PA

We conducted a locational screening analysis to identify feasible and favorable locations for each of the four CONE Areas. Our approach for identifying the representative locations within each CONE Area included three steps:

1. We identified candidate locations based on the revealed preference of actual plants built since 2014 or under construction to identify the areas of primary development, putting more weight on recent projects.

2. We sharpened the definition of likely areas for future development, depending on the extent of information available from the first step. For CONE Areas where recent

[28] PJM 2017 OATT, Section 5.10 a.

projects provide a clear signal of favored locations, we excluded only counties that would appear to be less attractive going forward, based on environmental constraints or economic costs (absent special offsetting factors we would not know about). For CONE Areas where the 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.

3. This approach results in identifying a specified area that spans several counties. For this reason, we developed cost estimates for each CONE Area by taking the average of cost inputs (*e.g.*, labor rates) across the specified locations.

The locations chosen for each CONE Area are shown in Figure 5. To provide a more detailed description of the specified locations, we show in Table 2 the cities used for estimating labor rates.

Our review of recent development in CONE Area 1 **Eastern MAAC (EMAAC)** resulted in identifying southern New Jersey and portions of northern Delaware, northeast Maryland, and southeast Pennsylvania as the reference resource location. We identified significant development in this region and northern New Jersey. Northern New Jersey projects are either located on brownfield sites or at existing sites, which are not widely available to future developers. Moreover, recent developments were more heavily concentrated in the southern portion of EMAAC. The economics are more favorable in this area with lower labor costs and higher energy market prices.

In CONE Area 2 **Southwest MAAC (SWMAAC)**, we maintained the same location as the 2014 CONE Study in southern Maryland, including portions of Charles, Prince George's, and Anne Arundel counties. There have been two new CC units developed in this region recently compared to a single CT in northern Maryland.

For the larger CONE Area 3 **Rest of RTO** CONE Area, the revealed preferences approach indicated two candidate regions based on our review of recently built or in-development plants: the region along the Pennsylvania-Ohio border and Virginia.[29] Although there have been more resources recently developed in Virginia, the majority of them are regulated and the development is over a larger area. The region along the Pennsylvania-Ohio border currently has three CCs under construction, has attractive energy market net revenues, and is in attainment for 8-hour ozone.

In CONE Area 4 **Western MAAC (WMAAC)**, developers have continued to demonstrate a willingness to build primarily in northeastern Pennsylvania, including areas around Allentown,

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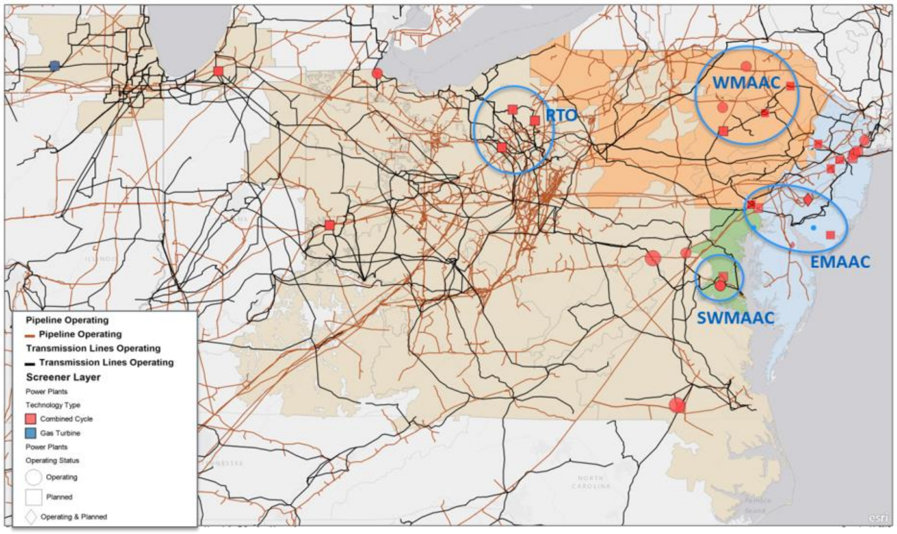
[29] Since the 2014 PJM CONE Study, the Dominion transmission zone has been added to the Rest of RTO CONE Area 3.

Scranton, and Wilkes-Barre. There have been several new units in this region, including two CCs that recently began operation and three more under construction.

Figure 5: Results of Locational Screening for each CONE Area



Sources and notes:
Data on operating and planned projects downloaded from SNL in August 2017.

Table 2: CONE Area Labor Pools

EMAAC	SWMAAC	Rest of RTO	WMAAC
Harrisburg, PA	Annapolis, MD	New Castle, PA	Wilkes-Barre, PA
Baltimore, MD		Youngstown, OH	Scranton, PA
Vineland, NJ		Columbus, OH	Williamsport, PA
Philadelphia, PA			Erie, PA
Dover, DE			

We calculate the plant operating characteristics (*e.g.*, net capacity and heat rate) of the reference resources using turbine vendors' performance estimation software for the combustion turbines' output and GateCycle software for the remainder of the CC plants.[30] For the specified locations within each CONE Area, we estimate the performance characteristics at a representative

30 GateCycle is a PC-based software application used for design and performance evaluation of thermal power plant systems at both design and off-design points. The GateCycle application allows for detailed analytical models for the thermodynamic, heat transfer, and fluid-mechanical processes within power plants.

elevation and at a temperature and humidity that reflects peak conditions in the median year.[31] The assumed ambient conditions for each location are shown in Table 3.

Table 3: Assumed PJM CONE Area Ambient Conditions

	CONE Area	Elevation *(ft)*	Max. Summer Temperature *(°F)*	Relative Humidity *(%RH)*
1	**EMAAC**	330	92.0	55.5
2	**SWMAAC**	150	96.0	44.6
3	**Rest of RTO**	990	89.8	49.7
4	**WMAAC**	1,200	91.2	49.2

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.

B. Summary of Reference Resource Specifications

Based on the assumptions discussed later in this section, the technical specifications for the CT and CC reference resources are shown in Table 4 and Table 5. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 3.

Table 4: CT Reference Resource Technical Specifications

Plant Characteristic	Specification
Turbine Model	GE 7HA.02
Configuration	1 x 0
Cooling System	n/a
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	352 / 355 / 321 / 344 *
Net Heat Rate (HHV in Btu/kWh)	9,274 / 9,270 / 9,221 / 9,263 *
Environmental Controls	
CO Catalyst	Yes, except for Rest of RTO
Selective Catalytic Reduction	Yes, except for Rest of RTO
Dual Fuel Capability	Yes
Firm Gas Contract	No
Special Structural Req.	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.

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[31] 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 5: CC Reference Resource Technical Specifications

Plant Characteristic	Specification
Turbine Model	GE 7HA.02
Configuration	2 x 1
Cooling System	Mechanical Draft Cooling Tower
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
w/o Duct Firing	1,023 / 1,031 / 1,012 / 1,001 *
with Duct Firing	1,152 / 1,160 / 1,138 / 1,126 *
Net Heat Rate (HHV in Btu/kWh)	
w/o Duct Firing	6,312 / 6,306 / 6,295 / 6,300 *
with Duct Firing	6,553 / 6,545 / 6,532 / 6,537 *
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	Yes, except for SWMAAC
Firm Gas Contract	SWMAAC only
Special Structural Req.	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.

C. Plant Size, Configuration and Turbine Model

While the turbine technology for each plant is specified in the tariff (*i.e.*, GE 7FA 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.[32] We reviewed CT and CC projects recently built or under construction in PJM and across the U.S. to determine the configuration, size, and turbine types for the reference resources.

1. Combined-Cycle Turbine Model, Configuration, and Duct Firing

Due to the almost exclusive development of CC plants in PJM in recent years, we focused our analysis of turbine models trends on the CCs. We found that the market is shifting away from the F-class and G-class frame type turbines that have been the dominant turbines over the past several decades and toward the larger H-class and J-class turbines. The larger H-class machine is an incremental evolution of the F-class machine with similar firing technologies. This presents low risk in terms of the maturity of the technology.

As shown in Table 6, over half of the CC plants installed or under construction in PJM since 2014 have installed H/J-class turbines. All of the CCs that cleared in the 2019/20 and 2020/21 BRAs are installing H/J-class turbines. In addition, we reviewed recent orders for GE turbines and

32 PJM 2017 OATT, Part 1 - Common Services Provisions, Section 1 - Definitions.

found that future CCs are almost exclusively using the H-class turbines.[33] This shows a clear trend toward the H/J-class turbine relative to past studies.[34] We selected the GE 7HA due to its slightly higher installed capacity. Other equivalent machines to the GE H-class machine such as the Siemens 9000HL or the Mitsubishi M501JAC have seen low market penetration in the U.S. at the time of this report. In addition, compared to equivalent models, the GE 7HA has been proven with more operating experience in the industry than other H-class equivalent gas turbine models.

Table 6: Turbine Model of Combined-Cycle Plants Built or Under Construction in PJM since 2014

Turbine Model	PJM Installed Capacity *(MW)*	U.S. Installed Capacity *(MW)*
General Electric 7HA	4,469	7,678
General Electric 7FA	4,436	11,422
Siemens SGT6-8000H	4,228	6,717
Siemens SGT6-5000F	4,140	8,306
Mitsubishi M501J	3,936	4,452
Mitsubishi M501G	2,775	6,310
General Electric 6B	251	251
Siemens SGT6-500	0	642
General Electric LM6000	0	331
Siemens V84.2	0	243
Siemens SGT6-800	0	127
Total	**24,235**	**46,480**
F/G Class Total	11,351	26,039
H/J Class Total	12,633	18,847

Sources and notes:
Data downloaded from ABB Inc.'s Energy Velocity Suite, August 2017.

Reflecting the shifts in turbine models, the size of recently developed CC plants is increasing. Although the most common range remains 700–900 MW as shown in Table 7, there has been 6,000 MW of capacity of new units in the 900–1,100 MW range (compared to 1,300 MW in the 2014 study) and 5,700 MW of units with capacity greater than 1,000 MW. In addition, the most common configuration remains the 2×1 (two gas combustion turbines, one steam turbine).[35] For this reason, we have maintained our assumption that the reference CC is a 2×1 plant.

33 We reviewed GE Power & Water's H-Class Gas Turbine Experience List from November 2016 and the 7F.05 Gas Turbine Experience List from June 2016.

34 In the 2014 CONE Study, there was just 1,500 MW of H/J-class turbines.

35 The CCs that most recently cleared the market are primarily 2x1 units with an average capacity of around 1,000 MW.

Table 7: Capacity and Configuration of CC Plants Built or Under Construction in PJM since 2014

	Plant Summer Capacity Range (MW)							
	< 300	**300 - 500**	**500 - 700**	**700 - 900**	**900 - 1,100**	**1,100 -1,300**	**> 1,300**	**Total**
CT x ST	*(GW)*	*(GW)*	*(GW)*	*(GW)*	*(GW)*	*(GW)*	*(GW)*	***(GW)***
1 x 1	0.0	1.2	0.0	0.7	0.0	0.0	0.0	**1.9**
2 x 1	0.0	0.0	2.0	6.3	3.9	0.0	0.0	**12.2**
3 x 1	0.0	0.0	0.0	0.0	1.1	0.0	5.7	**6.8**
2 x 2	0.0	0.0	0.6	1.5	1.0	0.0	0.0	**3.1**
Total	**0.0**	**1.2**	**2.6**	**8.6**	**6.0**	**0.0**	**5.7**	**24.0**

Sources and notes:
Data downloaded from ABB Inc.'s Energy Velocity Suite August 2017.

Based on the local ambient condition assumptions in Table 3, we specify the 2×1 CC reference resource's summer capacity to range from 1,001 MW to 1,031 MW prior to considering supplemental duct firing.

For the reference CC plant, supplemental firing of the steam generator, known as "duct firing," increases steam production and hence increases the output of the steam turbine.[36] Duct firing is common, although there is no standard optimized design. The decision to incorporate supplemental firing with the plant configuration and the amount of firing depends on the owner's preference and perceived economic value. We assumed the reference CC plant would add duct firing sufficient to increase the net plant capacity by 125–129 MW, or 13%, close to the average of CC plants constructed since 2007 or in development in PJM of 12%.[37] With duct firing, the max summer net capacity of the CC increases to 1,126–1,160 MW across CONE Areas.[38]

2. Combustion Turbine Model and Configuration

For the CT reference plant, there has been very limited development of frame-type CTs in PJM since 2007, as shown in Table 8. The GE 7FA continues to be the turbine with the most capacity added in PJM since 2007.[39]

36 Including duct firing increases the net capacity of the plant but reduces efficiency due to the higher incremental heat rate of the supplemental firing (when operating in duct firing mode) and the reduced efficiency of steam turbine (when not operating at full output). The estimated heat rates and capacities take account for this effect.

37 The average incremental capacity provided by including duct firing capabilities for CC plants constructed since 2007 and in development is 12% for plants in PJM and 15% for plants across the US. Data downloaded from ABB Inc.'s *Energy Velocity Suite* in August 2017.

38 The CC is based on a flexible CC design that has become an industry standard due to its ability to accommodate cycle.

39 The three 7FA turbines were added at Dominion's Ladysmith plant in 2008 and 2009.

Table 8: Turbine Model of CT Plants Built or Under Construction in PJM and the U.S. since 2007

Turbine Model	Turbine Class	PJM (count)	PJM (MW)	U.S. (count)	U.S. (MW)
General Electric 7FA	Frame	3	481	26	4,289
Pratt & Whitney FT8	N.A.	6	339	31	1,664
General Electric LM6000	Aeroderivative	7	317	96	4,360
General Electric LMS100	Aeroderivative	3	273	43	4,050
Rolls Royce Corp Trent 60	Aeroderivative	2	124	4	230
Pratt & Whitney FT4000	N.A.	2	120	2	120
Siemens SGT6-5000F	Frame	0	0	14	2,597
General Electric 7EA	Small Frame	0	0	21	1,492
General Electric 7FB	Frame	0	0	3	699
General Electric 7HA	Frame	0	0	2	612
Rolls Royce Corp Unknown	N.A.	0	0	8	480
Pratt & Whitney Unknown	N.A.	0	0	6	332
Westinghouse 501D5	N.A.	0	0	1	121
General Electric LM2500	Aeroderivative	0	0	4	65
Siemens Unknown	N.A.	0	0	2	29
Total		**23**	**1,654**	**263**	**21,140**

Sources and notes:
Data downloaded from ABB Inc.'s Energy Velocity Suite August 2017.

While the GE 7FA remains the most common frame-type turbine to be built since 2007, we reviewed additional sources due to the growing prevalence of the H-class turbines for use in a combined-cycle configuration, including recently proposed CTs in merchant markets, the performance characteristics of the turbines, the projected turbine costs, and PJM's Independent Market Monitor's (IMM's) assumptions for new entrants in the State of the Market report. We found that, although there are limited new frame-type turbines proposed to be built in the U.S. in simple-cycle configuration, both the GE 7FA and GE 7HA are currently being considered for CT development. The 7HA specifically is proposed for the Canal 3 plant in ISO-NE and for the Puente Power Project in CAISO.[40] In addition, the 7HA heat rate and costs on a per-kW basis are more attractive, and PJM's IMM has used the H-class turbine as the basis 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 reference resource 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), reflecting the configuration recently proposed for the CTs with GE 7HA turbines in Massachusetts and California.[41] We specify the

40 The Puente Power Project was cancelled following the recommendation of commissioners of the California Energy Commission to reject the plant following significant intervenor push back.

41 The 2014 PJM CONE study assumed the CT plant included two 7FA turbines ("2×0" configuration).

CT reference resource capacity and heat rate in the CONE Areas based on the local conditions assumptions in Table 3, with the CT capacities ranging from 321 to 355 MW.[42]

D. Detailed Technical Specifications

The majority of the specifications have remained the same as the 2014 CONE Study. In this section, we discuss the fuel supply assumptions and environmental controls. We discuss other technical specifications that are consistent with the 2014 CONE study in Appendix A.

1. Emissions Controls

Emissions control technology requirements for new major stationary sources are determined through the New Source Review (NSR) pre-construction permitting program. The NSR permitting program evaluates the quantity of regulated air pollutants the proposed facility has the "potential to emit" and determines the appropriate emissions control technology/practice required for each air pollutant. The regulated air pollutants that will have the most impact on emissions control technology requirements for new CTs and CCs are nitrogen oxides (NOx) and carbon monoxide (CO).

NOx and CO emissions from proposed gas-fired facilities located in PJM are evaluated through two different types of NSR permitting requirements:

- Non-attainment NSR (NNSR) for NOx emissions (applies to all site locations within the Ozone Transport Region, or OTR); and
- Prevention of Significant Deterioration (PSD) for CO emissions (entire PJM territory) and NOx emissions (eastern Ohio portion of Rest of RTO).

For new facilities located within the OTR, NOx emissions are evaluated through the NNSR permitting program if potential NOx emissions exceed the applicable annual emissions threshold. The OTR includes Delaware, the District of Columbia, Maryland, New Jersey, New York, Pennsylvania, and portions of Virginia. Except for portions of the Rest of RTO, all of the CONE Areas in PJM are within the OTR, and thus emissions of NOx from proposed facilities are treated as a non-attainment air pollutant and evaluated through NNSR. The portion of the Rest of RTO CONE Area identified through the locational analysis in eastern Ohio is currently classified as

[42] Note that we account for the lack of a Selective Catalytic Reduction (SCR) package installed on the CT in the Rest of RTO (CONE Area 3) in setting the max summer capacity of the unit. We describe the basis for not including the SCR in this area in the next section. Without the SCR, the unit is likely to be tuned to reduce NOx emissions, which reduces the max output. We have confirmed that this approach is more economical than installing the SCR and gaining the additional capacity. The developer will have to accept a federally-enforceable annual run-hour limitation.

"attainment," "unclassified," or "maintenance" for 8-hour ozone; therefore, PSD permitting applies to new facilities in the eastern Ohio region if NOx emissions exceed the annual threshold.

New CTs and CCs with no federally enforceable restrictions on operating hours are typically deemed a major source of NOx emissions, and therefore, trigger a Lowest Achievable Emissions Rate (LAER) or Best Available Control Technology (BACT) analysis to evaluate NOx emission control technologies. The NOx emission control technology required by the LAER or BACT analysis is likely to be a selective catalytic reduction (SCR) system. SCR systems are widely recognized as viable technology on aeroderivative and smaller E-class frame combustion turbines and have more recently been demonstrated on F-class frame turbines.[43] In addition, we assume dry low NOx burners are necessary to achieve the required emissions reductions.

CO emissions are evaluated through the PSD permitting requirements, because the PJM region is designated as an attainment area for CO. New combustion turbine facilities with no operating hour restrictions typically have the potential to emit CO in a quantity that exceeds the significant emissions threshold for CO, and therefore, trigger a BACT analysis to evaluate CO emissions control technologies. The CO emissions control technology required as a result of a BACT analysis is likely to be an oxidation catalyst (CO catalyst) system.

Based on our review of the applicable environmental regulations pertinent to new units located in each CONE Area and the emissions rates of the reference resources, we assume an SCR and a CO Catalyst system as the likely requirements resulting from the NSR permitting program for new gas-fired facilities proposed in all CONE Areas, except a new CT in the Rest of RTO area.

For the Rest of RTO region, a new CT unit that primarily fires natural gas is likely to avoid SCR and CO catalyst by installing combustors capable of achieving 9 ppm NOx and 9 ppm CO and accepting a federally-enforced annual run limit that will be set in the range of 20–40%. In western PA, a new CT would likely need to limit annual operation to approximately 20% to keep NOx emissions below the threshold of 50 tons per year. In eastern Ohio region, a new CT would face an annual run limit of approximately 30–40% driven by EPA's greenhouse gas performance standards for new combustion turbines.[44]

The addition of the SCR and CO Catalyst system on the CTs in the non-Rest of RTO regions adds $24 million (in 2017 dollars) to the capital costs.[45] All CCs are equipped with the SCR and CO catalyst at an incremental cost of $50 million (in 2017 dollars).

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43 CCs with H-class turbines will use an SCR design similar to the F-class turbines. While the exhaust temperature is similar (the 7HA.02 is a bit higher by about 10°F), the exhaust flow of the 7HA.02 is about 35% more than the 7FA.02 and requires a larger tempering air system.

44 See 40 CFR Part 60 Subpart TTTT.

45 Including an SCR on the Rest of RTO CT increases the installed costs to $886/kW and CONE to $103,000/MW-year.

2. Fuel Supply Specifications

Natural gas-fired plants can be designed to operate solely on gas or with "dual-fuel" capability to burn both gas and diesel fuel. Dual-fuel plants allow the turbines to switch between the lower cost fuel sources depending on market conditions and fuel availability. An alternative approach for securing fuel supply for gas plants is to procure firm transportation service on the gas pipelines, although in most cases including dual-fuel capabilities is the lower cost approach.[46] In our review of recent generation projects, we found that developers have been choosing in some cases to install dual-fuel capability or obtain firm gas contracts, although several new units have chosen neither option. Adding secure fuel supply capabilities has increased since the 2014 PJM CONE Study following the adoption of the Capacity Performance market design in which units are exposed to incentive payments during shortage conditions.

To reflect the changes in the market rules since the 2014 study, we updated our assumption from the 2014 PJM CONE Study such that the reference CT and CC plants would either install dual-fuel capability or procure firm transportation service in all CONE Areas.[47] Specifically, we assume all units add dual-fuel capabilities, except the SWMAAC CC, which procures firm transportation service.

We assume the dual-fuel plants are equipped with enough liquid fuel storage and infrastructure on-site for three days of continuous operation. Dual-fuel capability requires the combustion turbines to have water injection nozzles to reduce NOx emissions while firing liquid fuel. These modifications as well as the costs associated with fuel oil testing, commissioning, inventory, and the capital carrying charges on the additional capital costs contribute to the overall costs for dual-fuel capability. The incremental cost is approximately $14 million for the CT and $16 million for the CC (in 2017 dollars), including equipment, labor, and materials, indirect costs, and fuel inventory, which contributes approximately $7,000/MW-year to the CONE for the CT and $2,500/MW-year for the CC (in 2022 dollars).

We maintained our assumption that CCs in SWMAAC will obtain firm gas contractions based on the recent experience of new CCs in this area.[48] Both of the CCs recently developed in SWMAAC have entered into long-term firm transportation service contracts to obtain gas on the

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46 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

47 We recommended in the 2014 PJM CONE Study dual-fuel capabilities in all CONE Areas except Rest of RTO. PJM chose to adopt CONE values that incorporated dual-fuel capabilities.

48 We do not assume firm transportation for the reference CT plant since firm gas is unlikely to be economic for a plant that operates at a low capacity factor. We assume the CT will have dual-fuel capability.

Dominion Cove Point (DCP) pipeline.[49] The costs of firm transportation service are incurred annually so we include these costs as fixed operations and maintenance costs in the following section. Firm transportation itself costs about twice as much as installing dual-fuel capability.

IV. Plant Capital Cost Estimates

Plant capital costs are those 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 2017 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 simple- and combined-cycle plants are based on S&L experience on similarly sized and configured facilities and are explained in further detail in Appendix B.

Based on the monthly construction drawdown schedule, we estimate the overnight capital cost in 2022 dollars by escalating the 2017 cost data using reasonable escalation rates. The 2022 "installed cost" is the present value of the construction period cash flows as of the end of the construction period and is calculated using the monthly drawdown schedule and the cost of capital for the project.

A. Plant Capital Cost Summary

Based on the technical specifications for the reference CT and CC described above, the total capital costs for plants with an online date of June 1, 2022 are shown in Table 9 and Table 10 below. The methodology and assumptions for developing the capital cost line items are described further below.

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49 153 F.E.R.C. ¶ 61,074 (Issued October 20, 2015).

Table 9: Plant Capital Costs for CT Reference Resource in Nominal $ for 2022 Online Date

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*352 MW*	*355 MW*	*321 MW*	*344 MW*
Owner Furnished Equipment				
Gas Turbines	$74.4	$74.4	$74.4	$74.4
SCR	$26.6	$26.6	$0.0	$26.6
Sales Tax	$6.7	$6.1	$4.7	$6.4
Total Owner Furnished Equipment	**$107.7**	**$107.1**	**$79.1**	**$107.4**
EPC Costs				
Equipment				
Other Equipment	$25.7	$25.6	$28.5	$25.7
Construction Labor	$43.5	$31.8	$31.0	$37.6
Other Labor	$16.5	$15.3	$12.9	$16.0
Materials	$6.6	$6.5	$6.5	$6.6
Sales Tax	$2.1	$1.9	$2.2	$2.0
EPC Contractor Fee	$20.2	$18.8	$16.0	$19.5
EPC Contingency	$22.2	$20.7	$17.6	$21.5
Total EPC Costs	**$136.8**	**$120.5**	**$114.8**	**$128.9**
Non-EPC Costs				
Project Development	$12.2	$11.4	$9.7	$11.8
Mobilization and Start-Up	$2.4	$2.3	$1.9	$2.4
Net Start-Up Fuel Costs	$2.6	$1.7	$0.2	$0.6
Electrical Interconnection	$7.8	$7.8	$7.1	$7.6
Gas Interconnection	$29.1	$29.1	$29.1	$29.1
Land	$0.4	$0.7	$0.3	$0.5
Fuel Inventories	$3.0	$3.0	$2.7	$2.9
Non-Fuel Inventories	$1.2	$1.1	$1.0	$1.2
Owner's Contingency	$4.7	$4.6	$4.2	$4.5
Financing Fees	$8.0	$7.5	$6.5	$7.7
Total Non-EPC Costs	**$71.4**	**$69.2**	**$62.6**	**$68.3**
Total Capital Costs	**$316.0**	**$296.8**	**$256.5**	**$304.7**
Overnight Capital Costs ($million)	**$316**	**$297**	**$257**	**$305**
Overnight Capital Costs ($/kW)	**$898**	**$836**	**$799**	**$886**
Installed Cost ($/kW)	**$938**	**$874**	**$835**	**$925**

Table 10: Plant Capital Costs for CC Reference Resource in Nominal $ for 2022 Online Date

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*1152 MW*	*1160 MW*	*1138 MW*	*1126 MW*
Owner Furnished Equipment				
Gas Turbines	$173.2	$167.5	$173.2	$173.2
HRSG / SCR	$55.4	$53.6	$55.4	$55.4
Sales Tax	$15.1	$13.3	$14.5	$14.5
Total Owner Furnished Equipment	**$243.8**	**$234.4**	**$243.1**	**$243.1**
EPC Costs				
Equipment				
Condenser	$5.8	$5.8	$5.8	$5.8
Steam Turbines	$47.1	$45.5	$47.1	$47.1
Other Equipment	$74.7	$72.1	$74.7	$74.7
Construction Labor	$211.1	$159.3	$167.4	$187.2
Other Labor	$56.5	$50.6	$52.5	$54.3
Materials	$51.5	$51.2	$51.5	$51.5
Sales Tax	$11.9	$10.5	$11.4	$11.4
EPC Contractor Fee	$70.2	$62.9	$65.3	$67.5
EPC Contingency	$77.3	$69.2	$71.9	$74.3
Total EPC Costs	**$606.1**	**$527.3**	**$547.6**	**$573.7**
Non-EPC Costs				
Project Development	$42.5	$38.1	$39.5	$40.8
Mobilization and Start-Up	$8.5	$7.6	$7.9	$8.2
Net Start-Up Fuel Costs	$0.8	-$5.5	-$10.5	-$7.2
Electrical Interconnection	$25.5	$25.6	$25.2	$24.9
Gas Interconnection	$29.1	$29.1	$29.1	$29.1
Land	$1.5	$2.7	$1.0	$2.0
Fuel Inventories	$6.9	$0.0	$6.8	$6.7
Non-Fuel Inventories	$4.2	$3.8	$4.0	$4.1
Owner's Contingency	$9.5	$8.1	$8.2	$8.7
Emission Reduction Credit	$2.2	$2.2	$2.2	$2.2
Financing Fees	$25.5	$22.7	$23.5	$24.3
Total Non-EPC Costs	**$156.1**	**$134.4**	**$136.9**	**$143.9**
Total Capital Costs	**$1,006.0**	**$896.1**	**$927.6**	**$960.7**
Overnight Capital Costs ($million)	**$1,006**	**$896**	**$928**	**$961**
Overnight Capital Costs ($/kW)	**$873**	**$772**	**$815**	**$853**
Installed Cost ($/kW)	**$951**	**$841**	**$887**	**$929**

B. Plant Proper Capital Costs

1. Plant Developer and Contractor 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.

2. Equipment and Sales Tax

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines, where applicable. Note that the gas turbines for the CC cost more per turbine than for the CT because the manufacturer includes additional valves, gas pre-treatment, and other components that are required for CC operation.

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. A sales tax rate specific to each CONE Area is applied to the sum of major equipment and other equipment to account for the sales tax on all equipment.[50]

3. Labor and Materials

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.

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50 See the sales tax listed in Table 21 below.

Similar to the 2014 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, the labor rates have been developed by S&L through a survey of the prevalent wages in each region in 2017, 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 B.

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.

4. 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 CT and CC facilities based on S&L's proprietary project cost database. This value is lower than the 12% assumed in the 2014 PJM CONE Study for the CC facilities based on recent project history and current market trends.

"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, similar to the EPC contractor fee.

The overall contingency rate in this analysis (including the Owner's Contingency presented in the next section) is 9.3% to 9.5% of the pre-contingency overnight capital costs, slightly lower than the 9.6% in the 2014 Study due to lower Owner's Contingency, as explained below.

C. Owner's Capital 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.

1. 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.

2. Net Startup Fuel Costs

Before commencing full commercial operations, new generation 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 and ultra-lower sulfur diesel (ULSD) if dual-fuel capability is specified. 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 fuel oil consumption, and will receive revenues for its energy production. We provide additional detail on the calculation of the net startup fuel costs in Appendix B.

3. 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. In the 2014 PJM CONE Study the cost was small enough to be absorbed by the project development costs. Due to the large capacity of the units in the current study this assumption is no longer valid and the ERCs are included as a separate capital cost. ERCs are priced on a dollar per ton basis and are dependent on market conditions. Based on our research we have assumed a cost of $5,000/ton and an offset ratio of 1.15 for NOx and VOC emissions, resulting in a one-time cost of $2 million (in 2017 dollars) prior to beginning operation of the CC plants. CT plants are not required to purchase ERCs because they are not projected to exceed the NSR threshold.

4. 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 2014 PJM CONE Study. From the data summarized in Appendix B, we estimate that gas interconnection costs for both the CT and CC will be $26.2 million (in 2017 dollars) based on $4.6 million/mile and $3.4 million for a metering station. Similar to the 2011 and 2014 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 2014 and 2017, we selected 12 projects (8,326 MW of total capacity) that are representative of interconnection costs for a new gas CT or CC and calculated a capacity-weighted average electrical interconnection cost of $19.9/kW (in 2017 dollars) for these projects, 33% lower than the 2014 CONE Study. The estimated electric interconnection costs are approximately $7 million for CTs and $23 million for CCs (in 2017 dollars). Appendix B presents additional details on the calculation of electric interconnection costs.

5. 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. A summary of the land costs are available in Appendix B. Table 11 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 needed for CT and 40 acres for CC.

Table 11: Cost of Land Purchased

CONE Area	Land Price *($/acre)*	Plot Size Gas CT *(acres)*	Plot Size Gas CC *(acres)*	Cost Gas CT *($m)*	Cost Gas CC *($m)*
1 EMAAC	$36,300	10	40	$0.36	$1.45
2 SWMAAC	$66,700	10	40	$0.67	$2.67
3 RTO	$26,200	10	40	$0.26	$1.05
4 WMAAC	$51,100	10	40	$0.51	$2.04

Sources and notes:
We assume land is bought in 2018, *i.e.*, 6 months to 1 year before the start of construction.

6. Fuel and Non-Fuel Inventories

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. We assume non-fuel working capital is 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.

We calculated the cost of the fuel inventory in areas with dual-fuel capability assuming a three day supply of ULSD fuel will be purchased prior to operation at a cost of $1.77/gallon, or $12.63/MMBtu (in 2022 dollars), based on current futures prices.[51]

7. 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.* We assumed an owner's contingency of 8% of Owner's Costs, which is lower than we assumed in previous reports (9% in the 2014 CONE Study) based on S&L's review of the most recent projects for which it has detailed information on actual owner's costs.

8. 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.[52] As explained below, the project is assumed to be 65% debt financed and 35% equity financed, an increase from 60% debt financed in the 2014 CONE Study.

D. Escalation to 2022 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period for each technology: 36 months for CCs and 20 months for CTs.[53] We escalated the 2017 estimates

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[51] Futures prices calculated using NY Harbor USLD and Brent Crude Oil futures. Data from Bloomberg, representing trade dates 07/31/2017 to 10/31/2017.

[52] As discussed in the Financial Assumptions section, we assume the plant is financed through a 60% debt and 40% equity capital structure.

[53] For CTs, the construction drawdown schedule occurs over 20 months with 80% of the costs incurred in the final 11 months prior to commercial operation. For CCs, the construction drawdown schedule occurs over 36 months with 80% of the costs incurred in the final 20 months prior to commercial operation.

of overnight capital cost components forward to the construction period for a June 2022 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term (approximately 20-year) historical trends relative to the general inflation rate for equipment and materials and labor. The real escalation rate for each cost category was then added to the assumed inflation rate of 2.2% (see Section VI.A) to determine the nominal escalation rates, as shown in Table 12.

Table 12: Capital Cost Escalation Rates

Capital Cost Component	Real Escalation Rate	Nominal Escalation Rate
Equipment and Materials	0.20%	2.40%
Labor	1.70%	3.90%

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 2017 overnight costs using the monthly capital drawdown schedule developed by Sargent & Lundy for an online date in June 2022.

However, 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 2022 online date, the land is thus assumed to be purchased in late 2018 such that current estimates are escalated 1 year using the long-term inflation rate of 2.2%.
- **Net Start-Up Fuel and Fuel Inventories**: no escalation was needed as we forecasted fuel and electricity prices in 2022 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 2014 CONE Study; the interconnection costs have been escalated specifically to these months.
- **Emission Reduction Credits**: escalated to the online start date of June 2022 using the long-term inflation rate of 2.2%.

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 2022 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 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.

V. Operation and Maintenance Costs

Once the plant enters commercial operation, the plant owners incur fixed O&M costs each year, including property tax, insurance, labor, minor 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) to inform PJM's future E&AS margin calculations.

A. Summary of O&M Costs

Table 13 and Table 14 summarize the fixed and variable O&M for plants with an online date of June 1, 2022. In Appendix C, we provide alternative O&M cost estimates in which we include major maintenance costs as fixed O&M.

Table 13: O&M Costs for CT Reference Resource

	CONE Area			
O&M Costs	**1 EMAAC** *352 MW*	**2 SWMAAC** *355 MW*	**3 Rest of RTO** *321 MW*	**4 WMAAC** *344 MW*
Fixed O&M (2022$ million)				
LTSA	\$0.3	\$0.3	\$0.3	\$0.3
Labor	\$1.1	\$1.2	\$0.8	\$0.9
Maintenance and Minor Repairs	\$0.5	\$0.5	\$0.5	\$0.5
Administrative and General	\$0.2	\$0.2	\$0.2	\$0.2
Asset Management	\$0.5	\$0.6	\$0.4	\$0.4
Property Taxes	\$0.3	\$4.1	\$1.8	\$0.3
Insurance	\$1.9	\$1.8	\$1.5	\$1.8
Working Capital	\$0.04	\$0.03	\$0.03	\$0.03
Total Fixed O&M (2022$ million)	**\$4.8**	**\$8.7**	**\$5.6**	**\$4.4**
Levelized Fixed O&M (2022$/MW-yr)	**\$13,600**	**\$24,400**	**\$17,300**	**\$12,600**
Variable O&M (2022$/MWh)				
Consumables, Waste Disposal, Other VOM	1.10	1.10	0.95	1.10
Total Variable O&M (2022$/MWh)	**1.10**	**1.10**	**0.95**	**1.10**
Major Maintenance - Starts Based ($/factored start, per turbine)	**23,464**	**23,464**	**23,464**	**23,464**

Table 14: O&M Costs for CC Reference Resource

O&M Costs	CONE Area 1 EMAAC *1152 MW*	2 SWMAAC *1160 MW*	3 Rest of RTO *1138 MW*	4 WMAAC *1126 MW*
Fixed O&M (2022$ million)				
LTSA	$0.5	$0.5	$0.5	$0.5
Labor	$5.8	$6.3	$4.4	$4.6
Maintenance and Minor Repairs	$5.9	$6.1	$5.4	$5.5
Administrative and General	$1.3	$1.4	$1.1	$1.2
Asset Management	$1.6	$1.7	$1.2	$1.3
Property Taxes	$2.0	$12.3	$7.1	$1.9
Insurance	$6.0	$5.4	$5.6	$5.8
Firm Gas Contract	$0.0	$9.7	$0.0	$0.0
Working Capital	$0.1	$0.1	$0.1	$0.1
Total Fixed O&M (2022$ million)	**$23.3**	**$43.5**	**$25.4**	**$20.9**
Levelized Fixed O&M (2022$/MW-yr)	**$20,200**	**$37,500**	**$22,300**	**$18,600**
Variable O&M (2022$/MWh)				
Major Maintenance - Hours Based	1.44	1.44	1.44	1.44
Consumables, Waste Disposal, Other VOM	0.67	0.67	0.67	0.67
Total Variable O&M (2022$/MWh)	**2.11**	**2.11**	**2.11**	**2.11**

B. 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).

1. 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. Each major maintenance cycle for a combustion turbine typically includes regular combustion inspections, periodic hot gas path inspections, and one major overhaul. We include the costs of long-term maintenance as variable O&M and monthly LTSA payments as fixed O&M.

Consistent with past CONE studies, we assume major maintenance and overhaul costs often specified in an LTSA are included as variable O&M costs. Separately, in Appendix C, we present alternative O&M costs and CONE values corresponding to PJM's current cost guidelines, which specify that major maintenance costs cannot be considered to be variable costs in cost-based energy offers.[54] We include the alternative cost and CONE estimates in the appendix because it differs from past CONE studies (so is harder to compare) and might not turn out to be appropriate if PJM's cost guidelines change. Indeed, PJM stakeholders' Markets Implementation Committee is addressing whether the PJM cost guidelines should be modified to allow major maintenance costs to be included in variable O&M costs.

2. Insurance and Asset Management Costs

We calculated insurance costs as 0.6% of the overnight capital cost per year, based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer. This value is consistent with the 2014 PJM CONE Study. We estimated the asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services from a sample of CT and CC plants in operation.

3. Property Tax

To estimate property tax, we researched tax regulations for the locations selected in each CONE Area, averaging the tax rates in the areas that include multiple states. We estimated the property taxes through bottom-up cost estimates that separately evaluated taxes on real property (including land and structural improvements) and personal property (the remainder of the plant) in each location. In this study, we did not incorporate any assumed Payment in Lieu of Taxes (PILOT) agreements. Although PILOT agreements could be executed between an individual plant developer and a county, these agreements are individually negotiated and may not be available on a similar basis for all plants.

Real property is taxed in all states containing reference plant locations we selected for the CONE Area. Personal property is taxed only in SWMAAC (Maryland) and Rest of RTO (Ohio). For power plants, the value of personal property tends to be much higher than the value of real property, since equipment costs make up the majority of the total capital cost. For this reason, property taxes for plants located in states that impose taxes on personal property will be significantly higher than plants located in states that do not.

To estimate real property taxes, we assumed the assessed value of land and structural improvements is the initial capital cost of these specific components. We determined assessment ratios and tax rates for each CONE Area by reviewing the publicly-posted tax rates for several counties within the specified locations and by contacting county and state tax assessors. (The tax rates assumed for each CONE Area are summarized in Table 15 with additional details in Appendix B.) We multiply the assessment ratio by the tax rate to determine the overall effective

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[54] PJM, PJM Manual 15: Cost Development Guidelines, pp. 15–29.

tax rate, and apply that rate to our estimate of assessed value. We assume that assessed value of real property will escalate in future years with inflation.

Table 15: 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	3.7%	n/a	n/a
2 SWMAAC			
Maryland	1.1%	1.4%	3.3%
3 RTO			
Ohio	2.0%	1.4%	See "SchC-NewProd (NG)" schedule
Pennsylvania	2.5%	n/a	n/a
4 WMAAC			
Pennsylvania	3.5%	n/a	n/a

Sources and notes:
See Appendix B for additional detail on inputs and sources.

Personal property taxes in the states of Maryland, Ohio, and Pennsylvania were estimated using a similar approach. As with real property, we multiply the local tax rate by the assessment ratio to determine the effective tax rate on assessed value. 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. For example, in Maryland, personal property is subject to straight-line depreciation of 3.3% per year.

4. Working Capital

We estimated the cost of maintaining working capital requirements for the reference CT and CC by first estimating the working capital requirements (calculated as accounts receivable minus accounts payable) as a percent of gross profit for 3 merchant generation companies: NRG, Calpine, and Dynegy. The weighted-average working capital requirement among these companies is 4.2% of gross profits.[55] Translated to the plant level, we estimate that the working capital requirement is approximately 0.8% of overnight costs in the first operating year (increasing with inflation thereafter). In the capital cost estimates, we do not include the working capital requirements but instead the cost of maintaining the working capital requirement based on the borrowing rate for short-term debt for BB rated companies 2.2%.[56]

55 Gross profits are revenues minus cost of goods sold, including variable and fixed O&M costs.

56 15-day average 3-month bond yield as of October 27, 2017, BFV USD Composite (BB), from Bloomberg.

5. Firm Transportation Service Contract in SWMAAC

The gas pipeline serving the part of SWMAAC we identified for the reference plants is the Dominion Cove Point (DCP) pipeline. We understand from shippers that they have had trouble obtaining gas on the DCP pipeline. Availability of interruptible service has been unreliable and inflexible with the pipeline being fully subscribed and unable to absorb substantial swings in usage within a day. To at least partially address this problem, we assume new CC plants will contract for firm transportation service on DCP. We assume that the new CT will not acquire firm service due to the relatively few hours such a plant is expected to operate.

To estimate the costs of acquiring firm transportation service on the DCP pipeline for a plant coming online in 2022, we assume the same transportation reservation rate on DCP as that filed for the St. Charles and Keys projects. The rates for St. Charles and Keys are $3.7417 and $5.4278 per dekatherm respectively for 2017 (St. Charles) and 2018 (Keys).[57] We then escalate to 2022 dollars, resulting in rates of $4.21 and $5.97 per dekatherm,[58] resulting in a $9.7 million annual cost, adding $9,800/MW-year to the CONE for CCs in SWMAAC. We provide additional detail on the cost calculation of acquiring firm transportation service in Appendix B.

C. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they inform the E&AS revenue offset calculations performed annually 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 costs related to major maintenance that are often specified in an LTSA are considered variable O&M costs, consistent with past CONE studies. We provide alternative O&M costs and CONE estimates with these costs considered to be fixed O&M costs in Appendix C.

D. Escalation to 2022 Costs

We escalated the components of the O&M cost estimates from 2017 to 2022 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 12) have been used to escalate the O&M costs. The assumed real escalation rate for labor is 1.7% per year, while those for other O&M costs are 0.2% per year.

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57 153 F.E.R.C. ¶ 61,074 (Issued October 20, 2015).

58 This does not include variable charges, which should not be included in CONE but should be accounted for in estimating energy margins to calculate Net CONE.

VI. Financial Assumptions

A. 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).[59] 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, and a final adjustment for the recent changes in corporate taxes.[60] Based on the empirical analysis completed in November 2017 under the then 35% federal tax rate,[61] we would have recommended 7.0% as the appropriate ATWACC to set the CONE price for a new merchant plant that will commence operation by 2022 (4.5 years from now assuming a mid-year commercial operation). Consistent with this ATWACC determination under the 35% federal tax rate regime, we would have recommended the following specific components for a new merchant plant: a capital structure of 65/35 debt-equity ratio, cost of debt 6.5% and return on equity (ROE) of 12.8%.[62]

After we completed the initial analysis in early November of 2017 for the 35% corporate tax rates, the U.S. Congress passed the Tax Cuts and Jobs Act. These changes in the tax system raise an immediate question: what is the impact of the tax law changes on cost of capital? For example, the cut in the federal corporate income tax rate reduces the tax advantage of debt relative to equity, which could lead to a higher equity ratio and, combined with a higher after-tax cost of debt, a higher ATWACC. But, the law changes are more fundamental and involve

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59 The "after-tax weighted-average cost of capital" (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).

60 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.

61 We choose November 2017 as the cutoff date so that we can obtain the latest quarterly financial reports by the sample companies. Annual 2017 financial reports for SEC-registered companies will not be filed until March 2018.

62 $6.5\% \times 65\% \times (1 - 40.5\%) + 12.8\% \times 35\% = 7.0\%$. The tax rate of 40.5% is a combined federal-state tax rate, where state taxes are deductible for federal taxes ($= 8.5\% + (1 - 8.5\%) \times 35\%$). Note that the ATWACC applied to the four CONE Areas varies very slightly with applicable state income tax rates, as discussed in the following section.

more than a cut in the federal corporate tax rate. Other major changes include the transition from a worldwide tax system to a territorial tax system and immediate expensing of qualified investments. Ultimately, estimating the cost of capital is an empirical matter to be based on the market data. Because of the fundamental changes introduced in the new tax law and near-term uncertainties around its interpretations and implementations, it will take time for companies and individuals to adjust investment/consumption and financing decisions and for the impacts on the cost of capital to be observable and estimable.

Since we need to recommend the CONE value for a reference resource before these uncertainties are fully resolved, we have to predict the likely impact of the new tax law on merchant generator cost of capital without a substantial body of empirical data. We thus focus our analysis on what changes in the companies' capital structure (equity and debt ratios), if any, would likely result from the most prominent change in the new law—the reduction in federal corporate income tax from 35% to 21%. This is a critical first step, as an investment's cost of equity and cost of debt depend on its capital structure.[63] Our review of the recent economic literature, both theoretical and empirical, regarding the tax impacts on capital structure suggest that the drop in federal income tax rate is unlikely to have a material impact on the firms' capital structure (see further details below). Therefore, we recommend the same cost of capital components (cost of equity, cost of debt (COD), and debt/equity ratios) that we have developed from the available empirical information under the 35% federal tax rate. Under these assumptions, the reduction of the federal tax rate to 21% reduces the debt tax shield and thus increases the ATWACC to 7.5%.[64]

As a point of reference, we summarize our two previous costs of capital recommendations under the old 35% federal tax rate and the current 2018 recommendation in Table 16 under both the 35% and 21% tax rates. Historical comparison can be easily made in the first three rows of Table 16 (all under the same tax rate). In the 2014 PJM CONE Study, we recommended an ATWACC of 8.0%.[65] At a slightly higher equity ratio (60/40), the cost of debt and return on equity were set at 7.0% and 13.8%, respectively. In 2011, we recommended a debt/equity ratio of 50/50, based on the market-value capital structure at the time. In the last six years, the equity ratios have declined, as the U.S. IPP industry continued its restructuring activities.

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63 Conceptually, the ATWACC is relatively constant over a broad range of capital structure ratios. In other words, tax deductibility of interest payments has a secondary if not negligent impact on cost of capital.

64 Under the new tax law, state taxes are not deductible. The combined state and federal tax rate for Maryland (SWMAAC) is then 21% + 8.25% = 29.25%. Thus, the ATWACC is estimated based on a 6.5% cost of debt, a 12.8% cost of equity, and a 35% equity ratio as follows: $6.5\% \times 65\% \times (1 - 29.25\%) + 12.8\% \times 35\% = 7.5\%$.

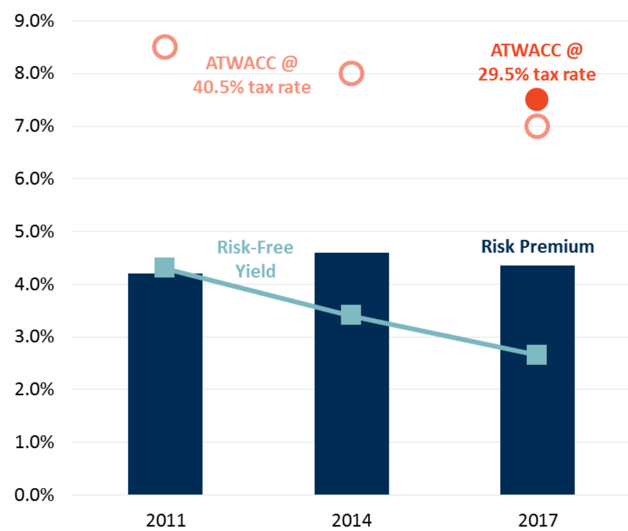
65 As discussed in our 2014 CONE report, our recommended 8.0% ATWACC was slightly above our ATWACC estimate for individual IPPs (7.8% for Calpine and 6.1% for both Dynegy and NRG), but within the range of cost of capital as suggested by the fairness opinions and analysts.

Table 16: Comparison of Cost of Capital Recommendations
(2011–17 at 40.5% combined federal/state tax rate vs. 2018 at 29.5% combined tax rate)

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	40.5%	12.8%	35%	6.5%	65%	7.0%
2018	**29.5%**	12.8%	35%	6.5%	65%	7.5%

The 2011–2018 reduction in ATWACC in our recommendations can be traced primarily to the fall in the long-term risk-free interest rate between 2011 to November 2017, with a partially offsetting increase from the lower tax rate.[66] This can be seen in Figure 6, where the red circles represent our ATWACC recommendations under the 35% federal tax rate, the red dot shows the ATWACC recommendation as a result of the tax law change, and the teal line displays the movement in risk-free rates. The risk premiums (ATWACC less risk-free rate) are shown in the blue bars. Viewed from this perspective, the risk premium implied from our current ATWACC recommendation is in line with the risk premiums implied in our 2011 and 2014 recommendations.[67] The ATWACC recommended as a result of the tax law change uses the same components (ROE, COD, and capital structure), except for the tax rate.

Figure 6: Comparison of Brattle Cost of Capital Recommendations for PJM



Sources and notes:
2011 and 2014 values based on previous PJM CONE studies.

66 20-year U.S. treasury yields increased slightly from November 2017 (about 2.6%) to mid-January 2018 (close to 2.8%).

67 In general, the fall in long-term risk-free rate caused ROE and Cost of Debt to fall, although the reduction is not uniform: as the market-value debt ratio increases from 50% in 2011 to 60% in 2014, our recommended ROE in 2014 increased relative to the 2011 recommendation.

The rest of this discussion proceeds in four topics to further document our approach to developing the recommended ATWACC. The first three are based on a 35% federal tax rate, as the empirical data are all related to corporate behaviors under the prior tax regime. First, we perform an independent cost of capital analysis for U.S.[68] and Canadian IPPs.[69] Second, we present evidence on the discount rates disclosed in fairness opinions for two recent merger and acquisition transactions involving U.S. IPPs.[70] Third, we discuss how considerations of the specific dynamics of PJM markets affect cost of capital recommendations. Finally, we discuss how cost of capital is expected to change due to the reduction in federal tax rate.

ATWACC for Publicly Traded Companies: We calculated ATWACC estimates using the following standard techniques with results summarized in Table 17 and charted with sensitivities in Figure 7. While we primarily rely on the estimated ATWACC results for the U.S. IPPs, Table 17 shows that the ATWACC results for the Canadian IPPs are in the same range as for the U.S. IPPs. For ease of presentation, Canadian IPP ATWACCs are not plotted in Figure 7.

Return on Equity: We estimate the required return on equity (ROE or cost of equity) using the Capital Asset Pricing Model applied to samples of U.S. and Canadian merchant generation companies. 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."[71] In Table 17, we use a risk-free rate of 2.65%, a 15-day average of 20-year U.S. treasuries as of October 2017, as our base case. We estimate the expected risk premium of the market to be 6.9% based on the long-term average of values provided by Duff and Phelps.[72] 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. The resulting required return on equity ranges from 8.5 to 12.8% for the sample companies included in the analysis. Because most of the sample companies will have

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68 The financial characteristics of the sample companies vary on an individual basis. For example, GenOn, a large subsidiary of NRG Energy filed for bankruptcy in June 2017 and will be restructured as a standalone business. Calpine announced it will be acquired by a private investor consortium while Dynegy will be acquired by Vistra Energy. We believe that these companies, each in differing positions, still can provide useful reference points for estimating the cost of capital for a merchant generator.

69 Since the U.S. IPP industry has been in the middle of restructuring and consolidation during the last five years, we consider a sample of Canadian IPPs as additional comparable companies.

70 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.

71 See, for example, Richard Brealey, Stewart C. Myers, and Franklin Allen (2011), *Principles of Corporate Finance*. New York: McGraw-Hill/Irwin (Chapter 8).

72 Duff and Phelps International Guide to Cost of Capital, 2017(arithmetic average of excess market returns over 20-year risk-free rate from 1926 to 2016).

various proportion of their generation assets under long-term contracts (*i.e.*, not operating on a purely merchant basis), we look to the upper range of these results as a reasonable estimate for the cost of equity of merchant generation investments in PJM.[73]

In addition to this baseline analysis under current market conditions, we consider the use of forecasted risk-free rates applicable for three years to reflect the fact that the ATWACC will be used to estimate offer prices of new merchant entrants that are supposed to start operation in 2022. The average 10-year Treasury yields of BlueChip's 5 year forecast (2019 to 2023) is 3.5%.[74] Adding a maturity premium (20-year bond yields over 10-year bond yields) of 0.54%, we estimate the 20-year risk-free rate to be 4.04% and use this as a sensitivity to our baseline ATWACC analysis, as shown in Figure 7 below (along with ATWACC benchmarks using fairness opinions from recent transactions as discussed further below).

Cost of Debt: In our 2011 and 2014 analyses, we estimated the COD based on the average bond yields corresponding to the unsecured senior credit ratings for each merchant generation company (issuer ratings).[75] The rating-based average yields, based on a sample of similarly-rated long-term (10-plus years) corporate bonds, are generally more preferable than the company's actual COD, which could be more influenced by company- and issue-specific factors.[76] 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 BB-based and B-based average yields for the general corporate bonds have dropped by more than 1.5 percent since 2016 and U.S.-based IPPs' company-specific bond yields are consistently higher than the rating-based yields. Therefore, in the current estimation (as shown in Table 17), we use the company-specific bond yield as our baseline case. (The rating-based yields are shown as Sensitivities 1 and 3 in Figure 7.)

Debt/Equity Ratio: We estimated the five-year average debt/equity ratio for each merchant generation company using data from Bloomberg as shown in Table 17.

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73 Note that, because of the 3-year forward nature of the PJM capacity market and its sloping demand curve, PJM merchant generation risks will be lower than the risk of merchant generation assets that do not have the benefit of a PJM-style capacity market (*e.g.*, as is the case in ERCOT and uncontracted plants in CAISO).

74 Blue Chip Economic Indicators (2017), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers, October 2017.

75 In Standard and Poor's (S&P) credit ratings, a company receives a higher rating based on its ability to meet financial commitments.

76 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 CODs. For example, the sample companies' credit ratings range from "BBB," with an associated COD of 3.5% to "B+," with an associated 5.0% COD. Using company-specific CODs, the range increases to 4.2–7.3%.

Table 17: Baseline ATWACC for the Publicly Traded Merchant Generation Companies (35% Federal Tax Rate)

Company	Firm Value [1]	S&P Credit Rating [2]	Equity Beta [3]	Return on Equity [4]	Cost of Debt [5]	Debt/ Equity Ratio [6]	After Tax WACC [7]
NRG Energy Inc	$23,278	BB-	1.17	10.7%	5.8%	73/27	5.4%
Calpine Corp	$16,586	B+	1.06	10.0%	5.6%	63/37	5.8%
Dynegy Inc	$9,903	B+	1.25	11.3%	6.7%	66/34	6.5%
TransAlta Corp	$4,020	BBB-	1.47	12.8%	6.3%	66/34	6.8%
Algonquin Power & Utilities Corp	$7,676	BBB	0.84	8.5%	5.1%	46/54	6.0%
Northland Power Inc	$9,003	BBB	0.92	9.0%	5.1%	58/42	5.6%
Capital Power Corp	$3,723	BBB-	0.95	9.2%	3.9%	47/53	6.0%

Sources and Notes:

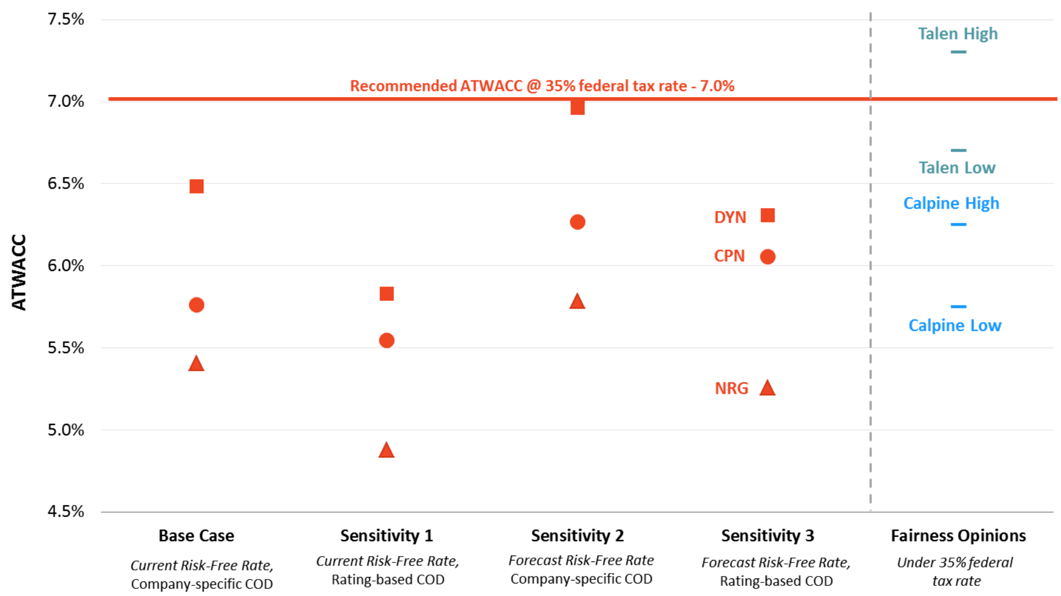
[1]: Market value of equity + Book value of debt, Bloomberg as of 11/1/2017
[2]: S&P Research Insight, Algonquin and Capital Power from SNL
[3]: Company-specific, Bloomberg as of 11/1/2017
[4]: Assumed risk-free rate (2.65%) + assumed market risk premium (6.90%) × [3]
[5]: Bloomberg as of 11/1/2017
[6]: Capital Structure calculated by Brattle using company 10-Ks and Bloomberg data
[7]: (% Debt) × [5] × (40.5% Combined state and federal tax rate; assumes 8.5% state tax rate) + (% Equity) × [4]

Figure 7 reports the ATWACC for the U.S. merchant sample (NRG, Calpine, and Dynegy) 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 17 above.
- *Sensitivity 1* uses the ratings-based COD, as used in previous PJM CONE studies.
- *Sensitivity 2* uses the forecasted risk-free rate.
- *Sensitivity 3* uses both the ratings-based COD and the forecasted risk-free rate.
- *Fairness Opinions* are from recent transactions (as discussed below).

As of November 2017, the federal tax rate was 35%. For the Base Case and each sensitivity (the first columns in Table 17), the red marks represent each of three U.S. IPPs' ATWACCs. For example, under Sensitivity 1, the ATWACCs (red marks) range approximately from 4.9% to 5.9%. Under the other two scenarios when the forecasted risk-free rate is used, the upper end of the ATWACC approached 7.0% (Sensitivity 2) and 6.3% (Sensitivity 3).

Figure 7: ATWACCs of U.S. IPPs and Discount Rates from Fairness Opinions (35% Federal Tax Rate)



Cost of Capital Benchmarks from Recent Fairness Opinions: Additional cost of capital reference points shown on the right side of Figure 7 above come from publicly-available values 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. For the current analysis, we found two additional reference points to inform the recommended ATWACC. The discount rate range disclosed in the June 2017 fairness opinion for the pending Calpine acquisition by Energy Capital Partners is 5.75% to 6.25%.[77] Another relevant reference point is the disclosed range of discount rate used in the acquisition of Talen Energy by Riverstone Holdings of 6.7% to 7.3%, released in December 2015.[78] We include these values in the figure above to compare the estimated ATWACC for publicly-traded companies under alternative assumptions for the risk-free rate and COD.

Estimated ATWACC for Merchant Generators in PJM Markets (before consideration of lower corporate tax rate): 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

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77 Definitive Proxy Statement, Schedule 14A, filed by Calpine Corporation with the SEC on November 14, 2017.

78 Preliminary Proxy Statement, Schedule 14A, filed by Talen Energy Corporation with SEC on July 1, 2016. Since December 2015 (the as-of date of the Talen discount rates), the 20-year risk-free rate has stayed about the same level. In December 2015 the 20-year risk-free yield was 2.61%, while as of 10/31/2017 it is 2.65% according to Bloomberg.

than for the average portfolio of independent power producers that have some long-term contracts in place.[79] As we have done in previous studies, we make an upward adjustment towards the upper end of the range from the comparable company results to reflect the relatively higher risk of merchant operations. Based on the set of reference points shown in Table 17 and Figure 7 above and the recognition of PJM merchant generation risk that exceeds the average risk of the publicly-traded generation companies, we believe that, under the 35% federal tax rate, a 7.0% ATWACC is the most reasonable estimate for the purpose of estimating CONE.[80] Our recommended 7.0% is above our own cost of capital estimates for the merchant companies and is at the high end of the range of discount rates disclosed in the fairness opinions.

Reduction in Federal Corporate Income Tax Rate and Cost of Capital: After we completed the above ATWACC analysis in early November 2017, the Tax Cuts and Jobs Act was passed in the U.S. Congress on December 22, 2017. More than three decades after the Tax Reform Act of 1986, the new tax law brings fundamental changes to the U.S. tax system including a substantial reduction in the federal income tax rate, a transition from worldwide tax to territorial tax, and immediate expensing of qualified investments. It is inevitable that businesses and individuals will adjust their investment, consumption, and financing decisions as a result of these changes in the tax code.[81] Given the complexity of the new tax law, the interpretation and implementation will not happen immediately, but take time to be fully incorporated in personal and corporate decisions. Moreover, the behaviors of economic agents will change over time. All of these imply that the impact of the new tax law on PJM merchant generating plants' cost of capital beyond 2022 is complex and will not be fully known until several years from now.

Nonetheless, we need to develop the PJM CONE values now, well ahead of the time when the impacts of the tax changes on project cost of capital can be measured empirically. ATWACC is a key input to the CONE calculation. Since the estimation of ATWACC depends on investment's capital structure, and a firm's COE and COD depend on the capital structure, we focus our investigation on how the impact of the tax rate reduction may affect the capital structure of investments. Conceptually, a decrease in the federal corporate income tax rate reduces the tax advantage of debt relative to equity. One would thus expect investors to choose a higher equity ratio under the lower tax rate. Combined with a higher after-tax cost of debt, ATWACC will thus increase. Empirically, is this prediction correct, and if so, how much will the capital structure adjust? To answer this question, we turn to the economic literature examining capital

79 This is not to say that the reference merchant project would not arrange some medium-term financial hedging tools.

80 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.

81 The new tax law lowers tax rates and elimination exception at the individual level. These too can have an impact on the capital structure.

structure decisions in response to prior changes in tax rates as "natural experiments,"[82] such as the federal corporate income tax rate reduction in the 1986 tax act (from 46% in 1986 to 34% in 1988), and numerous corporate income tax changes (both increases and decreases) at the state level.[83]

Researchers have made progress, both theoretically and empirically, in isolating the impact of tax rate changes on capital structure from U.S. historical experience.[84] The earliest research focused on the impact of a single event, the Tax Reform Act of 1986, on capital structure. According to the static "trade-off model" of capital structure, as illustrated in Figure 8, the optimal debt level is the point at which the marginal benefit of the interest tax shield (the flat line) equals the marginal cost of financial distress (the upward-sloping line).[85] Under this theory, the federal corporate tax rate reduction in the 1986 act should have led to a noticeable reduction in financial leverage, shown as a parallel shift downward of the marginal benefit line and a reduction in the optimal debt (D'<D).[86] However, as reported by Gordon and MacKie-Mason (1990), "the actual change in debt-to-value ratios has been substantially smaller than the models predict."[87] More recent papers examine tax law changes over a much longer period. For example, Graham, Leary, and Roberts (2015) investigate determinants of the century-long capital structure of U.S. publicly-traded companies, and conclude "corporate taxes underwent 30 revisions over the past century and increased from 10% to 52% between 1920 and 1950. Yet we find no significant time-series relation between taxes and the margin between debt usage and common equity."[88] Similarly, DeAngelo and Roll (2015) present time series evidence on the capital structure of 24

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82 These legislative decisions are quasi-experimental because they are largely out of the firms' control. Under these circumstances, researchers can more reliably infer the causal, instead of purely statistical, impact of tax rate changes on capital structure.

83 The basic premise behind our ATWACC approach that cost of capital is largely constant over a large range of capital structure is based on far larger empirical papers examining whether interest deduction affects capital structure using the cross-sectional evidence of firms' capital structure decisions. Tax rates are constant across firms and years in this literature.

84 There are also collaborations using international evidence. We limit our review to the U.S.

85 See, *e.g.*, Richard Brealey, Stewart C. Myers, and Franklin Allen (2011), *Principles of Corporate Finance*. New York: McGraw-Hill/Irwin (Chapter 18).

86 A complete analysis should incorporate the changes in personal taxes. In the case of 1986 tax act, the combined impact is to increase the tax advantage of debt. See Roger H. Gordon, and Jefrrey MacKie-Mason, 1990, "Effects of the Tax Reform Act on Corporate Financial Policy and Organization Form," NBER Working Paper No. 3222, at p. 7.

87 *Ibid.*, at p. 2. Their theoretical model suggests a 15.5% increase in debt/value ratio, but the observed increase was only 4.1% (at p. 16).

88 John R. Graham, Mark T. Leary, and Michael R. Roberts, 2015, "A Century of Capital Structure: The Leveraging of Corporate America," *Journal of Financial Economics* (118), 658–683.

Dow Jones Industrial Average (DJIA) companies over the last century.[89] None of the changes in capital structure are related to the tax reform act of 1986, and around 1986, DJIA companies' capital structure moved in different directions.

The empirical research above assumes a linear relationship between tax rates and debt ratios. Recent development in *dynamic* trade-off models,[90] however, predicts an asymmetric non-linear relationship: the debt ratios respond positively to tax rate increases, but do not react to tax rate reductions. Intuitively, a rise in the tax rate will increase the tax benefit of financial leverage, and incentivize the shareholders to borrow more. With a decrease in the tax rate, however, reducing borrowing will lower shareholders' option to default: this will benefit bond holders at shareholders' expense. Thus, shareholders have no incentive to reduce debt in the case of a tax rate reduction (D'=D in Figure 8b).[91] Heider and Ljungqvist (2015) confirm such an asymmetric relationship.[92] In their paper, the authors compile a large sample of 121 state-level tax rate increases or decreases between 1989 and 2011. The large sample of tax rate changes in multiple states over a long period of time allows the authors to design multiple empirical tests to confirm that their finding of an asymmetric impact of tax rates is robust and statistically significant.

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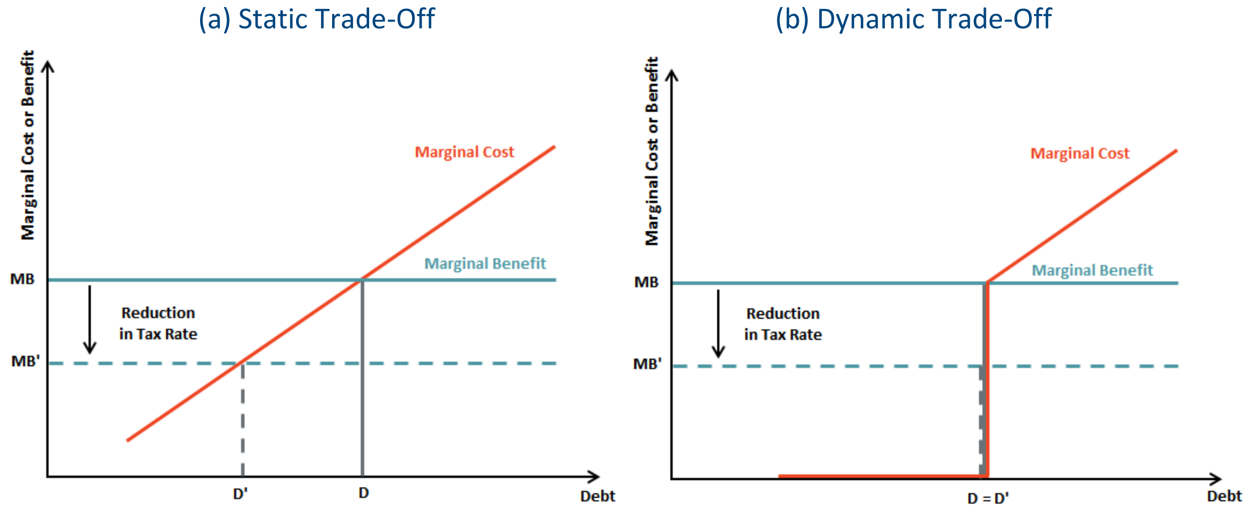
89 Harry DeAngelo, and Richard Roll, 2015, "How stable are corporate capital structures?," *Journal of Finance* (70), 373-418.

90 See, *e.g.*, Anat R. Admati, Peter M. DeMarzo, Martin F. Hellwig, Paul Pfleiderer, 2017, "The Leverage Ratchet Effect," forthcoming in *Journal of Finance*; and Christopher A. Hennessy, Akitada Kasahara, and Ilya A. Strebulaev, 2016, "Corporate Finance Responses to Exogenous Tax Changes: What Is the Null and Where Did It Come From?," Stanford University Working paper.

91 For example, Admati, *et al.*, *op cit.*, at p. 1 state "Once debt is in place, shareholders will resist any form of leverage reduction no matter how much the leverage reduction may increase total firm value. At the same time, shareholders would generally choose to increase leverage even if any new debt must be junior to existing debt. The resistance to leverage reductions, together with the desire to increase leverage, creates asymmetric forces in leverage adjustments that we call *the leverage ratchet effect*."

92 Florian Heider, and Alexander Ljungqvist, 2015, "As Certain as Debt and Taxes: Estimating the Tax Sensitivity of Leverage from State Tax Changes," *Journal of Financial Economics* (118), 684–712.

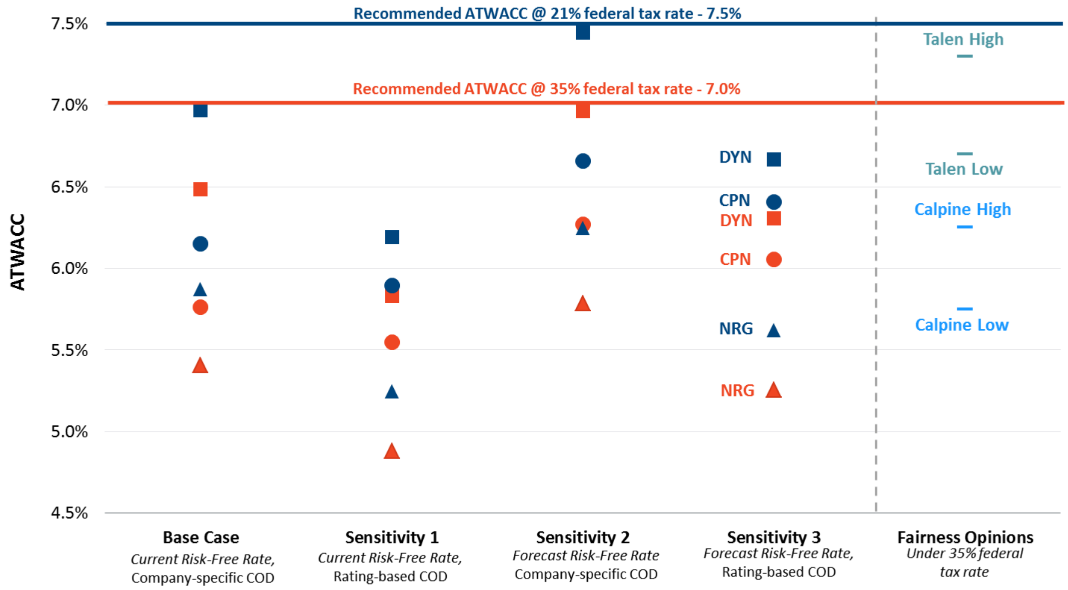
Figure 8: Illustrate Dynamic Trade-off of Tax Benefit and Cost



This research suggests that a decrease in the federal tax rate will *not* have a material impact on capital structure. As a result, we recommend retaining the components of ATWACC, *i.e.*, ROE, COD, and debt and equity ratios, based on our November 2017 analysis.[93] Figure 9 presents both the ATWACCs under the 35% and 21% federal tax rates. The blue marks represent ATWACCs of the U.S. IPPs under the 21% tax rate. The marginal impact of a lower federal tax rate increases cost of capital between 0.4% and 0.6%, which makes us increase the recommended ATWACC from 7.0% to 7.5% to reflect the impact of the reduced corporate tax rate as shown by the blue line in Figure 9.

93 We have verified that the sample companies' beta (based on five-year's historical data) and cost of debt stay more or less constant since November 2017.

Figure 9: ATWACCs of U.S. IPPs and Discount Rates from Fairness Opinions (35% and 21% Federal Tax Rate)



Note: Blue and red denote ATWACC estimates using federal corporate tax rates of 21% and 35%, respectively.

B. Other Financial Assumptions

Calculating CONE requires several other financial assumptions about general inflation rates, tax rates, depreciation, bonus depreciation, and interest during construction.

Inflation rates affect our CONE estimates by forming the basis for projected increases in various fixed O&M cost components over time. We calculated the 20-year inflation rate for four years from now implied by the Cleveland Federal Reserve's estimates of inflation of 2.2%.[94] The most forward looking forecast in the Blue Chip Economic Indicators report is 2.3%.[95] Based on these sources, we assumed for the CONE calculations an average long-term inflation rate of 2.2%.

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. We use a marginal federal corporate income tax rate of 21% as explained in the previous section due to the

94 As stated on the Cleveland Federal Reserve website, the Cleveland Fed's "inflation expectations model uses Treasury yields, inflation data, inflation swaps, and survey-based measures of inflation expectations to calculate the expected inflation rate (CPI) over the next 30 years." Federal Reserve Bank of Cleveland (2017), *Cleveland Fed Estimates of Inflation Expectations*, accessed November 11, 2017. Available at https://www.clevelandfed.org/our-research/indicators-and-data/inflation-expectations.aspx.

95 Blue Chip Economic Indicators (2017), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers, October 2017. We used the consensus ten-year average consumer price index (CPI) for all urban consumers.

passing of the Tax Cuts and Jobs Act. The state tax rates assumed for each CONE Area are shown in Table 18.

Table 18: State Corporate Income Tax Rates

CONE Area	Representative State	Corporate Income Tax Rate	Sales Tax Rate
1 Eastern MAAC	New Jersey	9.00%	6.63%
2 Southwest MAAC	Maryland	8.25%	6.00%
3 Rest of RTO	Pennsylvania	9.99%	6.34%
4 Western MAAC	Pennsylvania	9.99%	6.34%

Sources and notes:
State tax rates retrieved from www.taxfoundation.org

We calculated depreciation for the 2022/23 CONE parameter based on the bonus depreciation provisions of the 2017 Tax Cuts and Jobs Act. New units put in service before January 1, 2023 can apply 100% bonus depreciation in the first year of service, which decreases CT CONE on average by $11,700/MW-year and CC CONE on average by $14,400/MW-year. The bonus depreciation then phases out over five years, decreasing by 20% in each subsequent year such that plants in service before January 1, 2024 can utilize 80% bonus depreciation. For calculating depreciation for the 2023/24 auctions and later auctions, we apply the Modified Accelerated Cost Recovery System (MACRS) of 20 years for a CC plant and 15 years for a CT plant to the remaining depreciable costs (*i.e.*, 80% bonus depreciation, 20% MACRS in 2023/24).[96]

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 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.*, 60% debt and 7.0% COD.

[96] Internal Revenue Service (2013), *Publication 946, How to Depreciate Property,* February 15, 2013. Available at http://www.irs.gov/pub/irs-pdf/p946.pdf.

VII. CONE Estimates

Translating investment costs into annualized costs for the purpose of setting annual capacity prices requires an assumption about how net revenues are received over time to recover capital and annual fixed costs. "Level-nominal" cost recovery assumes that net revenues will be constant in nominal terms (*i.e.*, decreasing in real, inflation-adjusted dollar terms) over the 20-year economic life of the plant. A "level-real" cost recovery path starts lower in the first year (by about 16%) then increases at the rate of inflation (*i.e.*, is constant in real dollar terms).[97]

While there is no perfect way to capture developers' expectations for their future cost recovery paths, we previously reviewed long-term trends in plant costs and efficiency to understand the likely long-term drivers of new entry offers and whether a developer would expect that market revenues would lead to a more front-loaded or more back-loaded recovery of investment costs. This section of our report first re-visits the analysis of whether a level-nominal or level-real annualization approach is more consistent with market data and then presents the summary of CONE estimates by CONE Area.

A. Levelization Approach

In the 2011 PJM VRR Report, we analyzed the historical trends of turbine costs and heat rates to inform the potential of the cost recovery path for a new gas-fired generation resource. We found that over the previous 20 years combustion turbine costs increased on average by 0.6% per year faster than inflation and that the average heat rates of new gas-fired CTs decreased by approximately 100 Btu/kWh a year.[98] Based on this analysis, we found it likely that the net revenues for the marginal resources in the PJM capacity market would tend to increase approximately with inflation over time. We consequently recommended that PJM adopt a *level-real* cost recovery for calculating CONE to reflect these findings. We maintained this recommendation in the 2014 VRR Report.

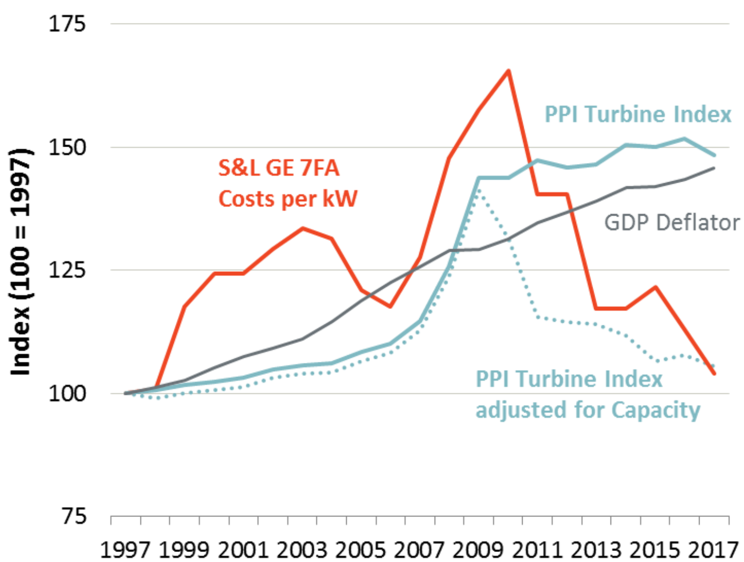
Updating this analysis based on the latest data available we come to superficially similar results: over the most recent 20-year period, the turbine cost indices that we relied on in 2011 escalated on average at 0.9% per year faster than inflation and the heat rate of CTs decreased by approximately 100 Btu/kWh on average. However, the turbine cost indices do not properly account for the significant increase in net plant output for F-class turbines (+42% since 2010 as discussed in Section II.B above) that have been installed in PJM most recently. Based on S&L cost estimates for over the past 20 years, the costs of GE 7FA turbines have declined by 37% on a per-kW basis since 2010, as shown by the red line in Figure 10 below. By comparison, the

97 Both cost recovery paths (level-real and level-nominal) are calculated such that the NPV of the project is zero over the 20-year economic life.

98 See The Brattle Group "Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM," August 24, 2011.

Producer Price Index (PPI) turbine cost index increased by 3% since 2010 (as shown by the solid teal line). While the PPI Turbine index shows a similar trend over the first thirteen years as the S&L estimates, the cost trends diverge once the net output of the F-class turbine starts increasing around 2010. To account for this recent change in turbine output, we adjusted the PPI Turbine index for the increases in plant capacity (shown as the dotted teal line) and observe that the adjusted index follows a similar trend to the GE 7FA costs over this period.[99] Our analysis shows that the assumption that costs per kW will continue to escalate slightly faster than inflation in the long-term may no longer apply. In fact, both the S&L GE 7FA cost per kW trend and the capacity-size adjusted PPI Turbine Index show that 2017 turbine costs are only slightly more expensive on a nominal $/kW basis than 20 years ago.

Figure 10: Gas Combustion Turbine Cost Trends since 1997



Sources and notes:
S&L cost estimates; BLS PPI Turbine & Turbine Generator Sets; Gas Turbine World.

Looking forward, there is no perfect way to project how cost trends will unfold and how gas-fired units expect to recover their costs.[100] In addition to the considerations analyzed above, developers of new generation resources must consider that the gas generation technologies are likely to continue to see periodic incremental improvements over time, similar to the downward

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99 We would not expect the GE 7FA index and adjusted PPI turbine index to perfectly align as the PPI includes a much wider range of turbine types. The BLS methodology for developing the PPIs mentions that in most cases the indices include a "quality adjustment" to account for such changes in product quality as seen here. However, this does not appear to be the case for the PPI turbine index based on our attempt at benchmarking the index against historical cost estimates for GE 7FA turbines.

100 As stated in our 2014 VRR Curve report, "one could make a case for attempting to determine projections of net revenues representing actual developers' likely views on energy prices, fuel prices, and capacity prices over the 20-year investment life. The entirety of this information is what ultimately determined the 'true' value of CONE." See 2014 VRR Curve Report, p. 11.

cost trend since 2010. Investors in new generating resources have to consider the possibility that their future net revenues may erode as technological innovation and environmental policies favor different types of technologies, such as renewable generation combined with storage.

Due to the lower escalation rate of gas turbine plants in $/kW terms than previously estimated and the potential for similar cost-reductions to arrive periodically over the 20-year economic life of new natural gas-fired generating plants, we recommend adopting the *level-nominal* approach for setting the 2022/23 CONE value.

B. SUMMARY OF CONE ESTIMATES

Table 19 and Table 20 show summaries of our plant capital costs, annual fixed costs, and levelized CONE estimates for the CT and CC reference plants for the 2022/23 delivery year. For comparison, the tables include the most recent 2021/22 PJM administrative CONE parameters escalated to a 2022/23 delivery year at 2.8% per year.

For the CT, the level-nominal CONE estimates range from $98,200/MW-year in the Rest of RTO to a high of $108,400/MW-year in SWMAAC. The updated estimates are lower than the previous parameters escalated to 2022/23 by 22–28% due to a decrease in capital costs and a lower ATWACC offset. Capital costs are lower primarily due to the lower tax rates, the change in turbine to the larger H-class turbine, and the change to a 1×0 configuration (reducing labor and equipment and materials costs. In addition, the reduction in ATWACC from 8.0% to 7.5% reduces CONE values by an average of 3.8%.

Table 19: Recommended CONE for CT Plants in 2022/2023

				Simple Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$316	$297	$257	$305
[2]	Installed (inc. IDC)	*$m*		$330	$310	$268	$318
[3]	First Year FOM	*$m/yr*		$5	$9	$6	$4
[4]	**Net Summer ICAP**	***MW***		**352**	**355**	**321**	**344**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$898	$836	$799	$886
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$938	$874	$835	$925
[7]	Levelized FOM	*$/kW-yr*	= [3] / [4]	$16	$24	$18	$15
[8]	**After-Tax WACC**	***%***		**7.4%**	**7.5%**	**7.4%**	**7.4%**
[9]	Effective Charge Rate	*%*		10.1%	10.1%	10.0%	10.0%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$106,400**	**$108,400**	**$98,200**	**$103,800**
	Prior Auction CONE						
[11]	PJM 2021/22 CONE	*$/MW-yr*		$133,144	$140,953	$133,016	$134,124
[12]	Escalated to 2022/23	*$/MW-yr*	= [11] x 1.028	$136,900	$144,900	$136,700	$137,900
	Difference between Updated CONE and Escalated Prior Auction CONE						
[13]	Escalated to 2022/23	*$/MW-yr*	= [10] - [12]	($30,400)	($36,500)	($38,600)	($34,000)
[14]	Escalated to 2022/23	*%*	= [13] / [12]	-22%	-25%	-28%	-25%

Sources and notes:

PJM 2021/22 parameters escalated to 2022/23 at 2.8% annually, based on S&L analysis of escalation rates for materials, turbine and labor costs.

CONE values expressed in 2022 dollars and ICAP terms.

The CT CONE estimates vary by CONE Area primarily due to differences in emissions controls technologies (no SCR in the Rest of RTO), labor rates (highest in EMAAC), and property taxes (highest in SWMAAC). The Rest of RTO is at the low end due to the change in specification for the CT in this CONE Area that no longer includes an SCR. EMAAC CONE ($106,400/MW-year) is closer in value to SWMAAC at the high end of the range despite significantly higher capital costs, but lower annual property taxes. The WMAAC CONE is lower than EMAAC primarily due to slightly lower labor costs.

For the CC, the level-nominal CONE estimates range from $109,800/MW-year in the Rest of RTO to $120,200/MW-year in SWMAAC. The updated estimates are 40–41% lower than the previous estimates escalated to 2022/23 primarily due to the economies of scale of the larger H-class turbines and the lower tax rates. Similar to the CT, the decrease in ATWACC further reduces the CONE by an additional 3.8%.

Table 20: Recommended CONE for CC Plants in 2022/2023

				Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,006	$896	$928	$961
[2]	Installed (inc. IDC)	*$m*		$1,095	$976	$1,009	$1,046
[3]	First Year FOM	*$m/yr*		$23	$43	$25	$21
[4]	**Net Summer ICAP**	***MW***		**1,152**	**1,160**	**1,138**	**1,126**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$873	$772	$815	$853
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$951	$841	$887	$929
[7]	Levelized FOM	*$/kW-yr*	= [3] / [4]	$24	$38	$24	$22
[8]	**After-Tax WACC**	***%***		**7.4%**	**7.5%**	**7.4%**	**7.4%**
[9]	Effective Charge Rate	*%*		10.6%	10.6%	10.5%	10.5%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$116,000**	**$120,200**	**$109,800**	**$111,800**
	Prior Auction CONE						
[11]	PJM 2021/22 CONE	*$/MW-yr*		$186,807	$193,562	$178,958	$185,418
[12]	Escalated to 2022/23	*$/MW-yr*	= [11] x 1.028	$192,000	$199,000	$184,000	$190,600
	Difference between Updated CONE and Escalated Prior Auction CONE						
[13]	Escalated to 2022/23	*$/MW-yr*	= [10] - [12]	($76,000)	($78,800)	($74,200)	($78,800)
[14]	Escalated to 2022/23	*%*	= [13] / [12]	-40%	-40%	-40%	-41%

Sources and notes:

PJM 2021/22 parameters escalated to 2022/23 at 2.8% annually, based on S&L analysis of escalation rates for materials, turbine and labor costs.

CONE values expressed in 2022 dollars and ICAP terms.

Differences in the CC CONE estimates across the CONE Areas are primarily due to differences in labor with the highest labor costs in EMAAC and lowest in Rest of RTO. Despite similar labor costs in SWMAAC compared to Rest of RTO, the SWMAAC CONE is greater than EMAAC due to its higher fixed O&M costs, as a result of higher property taxes, and the higher costs of the firm gas contracts (assumed necessary in SWMAAC) compared to the combination of non-firm gas contracts and dual fuel capability (assumed to be sufficient in EMAAC).

The updated CC CONE values have decreased significantly more over the prior estimates than the CT CONE values have, leading to a narrower cost premium for CCs of $8,000–11,800/MW-year compared to the $46,000–54,000/MW-year premium in the 2020/21 BRA parameters. The most significant driver narrowing the difference between CT and CC CONE is economies of scale with the very large CC based on the 7HA. While the capacity of the CCs plants has almost *doubled* compared to that in the 2014 CONE Study, the cost of the gas turbines increased by 50%, and the cost of the steam section of the CC (including the heat recovery steam generator and steam turbine) increased by only 30%. CT plants share the same economies of scale on the combustion turbine itself, but not the greater economies of scale the CCs enjoy on their steam section or other balance of plant costs. In the Rest of RTO CONE Area, the lack of the SCR on the CT results in an increased CC premium.

VIII. Annual CONE Updates

PJM's tariff specifies that CONE will be escalated annually 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 21 below, we recommend that PJM weight the components in the CT composite index based on 20% labor, 55% materials (increased from 50%), and 25% turbine (decreased from 30%). We recommend that PJM weight the CC components based on 30% labor (increased from 25%), 50% materials (decreased from 60%), and 20% turbine (increased from 15%).

Table 21: CONE Annual Update Composite Index

	Simple Cycle			Combined Cycle		
	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%	22%	20%	25%	30%	30%
Materials	50%	53%	55%	60%	52%	50%
Turbines	30%	26%	25%	15%	18%	20%

Sources and notes:
Values may not add up to 100% due to rounding.

PJM will need to account for bonus depreciation declining by 20% in subsequent years starting in 2023. We calculate that a reduction in the bonus depreciation by 20% increases the CT CONE by 2.2% and the CC CONE by 2.5% due to the decreasing depreciation tax shield. We recommend that after PJM has escalated CONE by the composite index, as noted above, PJM account for the declining tax advantages of decreased bonus depreciation by applying an additional gross up of 1.022 for CT and 1.025 for CCs.

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: Detailed Technical Specification Analysis

A. Combined Cycle Cooling System

For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell mechanical draft cooling tower, based on the predominance of cooling towers among new CCs and S&L recommendation.

Our review of EIA-860 data found that a majority of CC plants with a specified cooling system had a cooling tower installed, as shown in Table 22.

Table 22: Cooling System for CC Plants in PJM Built or Under Construction Since 2014

State	Once-Through *(MW)*	Cooling Tower *(MW)*	Dry Cooling *(MW)*
Delaware	0	309	0
Illinois	0	573	0
Indiana	0	642	0
Maryland	0	1,726	800
New Jersey	0	2,962	0
Ohio	0	2,173	683
Pennsylvania	1,064	4,314	3,905
Virginia	0	2,455	2,629
Total	**1,064**	**15,154**	**8,017**

Sources and notes:
Based on 2015 Form EIA-860 Data; cooling tower includes recirculating with forced, induced, and natural cooling towers.

We reviewed whether reclaimed water from municipal waste treatment centers would be available for use in the cooling systems to avoid environmental issues with withdrawing fresh water. Our review of the availability of reclaimed water indicated that EMAAC has at least two recently developed generating facilities that utilize reclaimed water. Previous research indicated that EMAAC has at least one waste water treatment facility per county, such that reclaimed water can be considered generally available. In Rest of RTO, we found one facility that utilized reclaimed water but did not find this is a predominant trend in the area. For SWMACC and WMAAC, municipal waste treatment facilities are much less common such that withdrawals from ground or surface water would be necessary. Our research did not identify any recently developed generating facilities that utilized reclaimed water in either CONE Area. In addition to environmental drivers for using reclaimed water, building the piping and treatment facilities required for ground or surface water costs $500k to $1 million more than for reclaimed water, depending on the location.

B. Power Augmentation

Evaporative coolers are included downstream of the filtration system to lower the combustion turbine inlet air temperature during warm weather operation. With a few exceptions the use of evaporative coolers has become a standard in industry practice where water is available. The use of evaporative coolers increases turbine output and efficiency for a small increase in capital cost. In addition, the combustion turbines in both simple- and combined-cycle arrangements are equipped with an inlet filtration system to protect from airborne dirt and particles. Evaporative coolers and associated equipment add $3 million per combustion turbine to the capital costs.

C. Black Start Capability

Based on our analysis in the 2011 PJM CONE Study, we did not include black start capability in either the CC or CT reference units because few recently built gas units have this capability.

D. Electrical Interconnection

While all CONE Areas have a variety of transmission voltages, both lower and higher than 345 kV, we selected 345 kV as the typical voltage for new CT and CC plants to interconnect to the transmission grid in PJM. The switchyard is assumed to be within the plant boundary and is counted as an EPC cost under "Other Equipment," including generator circuit breakers, main power and auxiliary generator step-up transformers, and switchgear. All other electric interconnection equipment, including generator lead and network upgrades, is included separately under Owner's Costs, as presented in Section IV.C.4.

E. Gas Compression

Similar to the 2014 PJM CONE Study, we assume gas compression would not be needed for new gas plants with frame-type combustion turbines located near and/or along the major gas pipelines selected in our study. The frame machines generally operate at lower gas pressures than the gas pipelines.

Appendix B: Detailed Cost Estimate Assumptions

A. 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 2017. 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 work week with per-diem included to attract skilled labor.

Labor rates have been updated since the 2014 CONE study to represent the current competitive market. Additionally, 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. As a result, the labor rates in this CONE study are lower than those in the 2014 CONE study by approximately 5% for CTs and 6% for CCs on average.

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 were used in the 2014 PJM CONE Study and are in-line with recent projects in which S&L has been involved.

A summary of construction labor cost assumptions is shown below in Table 23.

Table 23: Construction Labor Cost Assumptions

		EMAAC	SWMAAC	Rest of RTO	WMAAC
CT Plant					
2017 Construction Labor Hours	*hours*	260,918	238,253	225,598	258,762
2017 Weighted Average Crew Rates	*$*	119.54	91.59	96.46	102.89
2017 Productivity Factor	--	1.18	1.10	1.12	1.17
2017 Construction Labor Costs	*$*	$36,729,452	$26,839,467	$26,229,993	$31,795,172
2017 Construction Labor Costs	*$/kW*	104	76	82	92
CC Plant					
2017 Construction Labor Hours	*hours*	1,240,716	1,148,990	1,179,563	1,230,523
2017 Weighted Average Crew Rates	*$*	125.85	100.39	103.05	111.38
2017 Productivity Factor	--	1.18	1.10	1.12	1.17
2017 Construction Labor Costs	*$*	$182,316,769	$137,591,371	$144,572,598	$161,654,881
2017 Construction Labor Costs	*$/kW*	158	119	127	144

B. 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 10/10/2017 to estimate 2022 gas prices.
- **Fuel Oil**: rely on No. 2 fuel oil futures for New York harbor through January 2021; escalate fuel oil prices between January 2021 and an assumed fuel delivery date of May 2022 based on the escalation in Brent crude oil futures over the same date range.
- **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;[101] 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.

Table 24: 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	Fuel Oil Use	Fuel Oil Price	Fuel Oil Cost	Total Cost
	(MWh)	*($/MWh)*	*($m)*	*(MMBtu)*	*($/MMBtu)*	*($m)*	*(MMBtu)*	*($/MMBtu)*	*($m)*	*($m)*
Gas CT										
1 Eastern MAAC	186,984	$22.51	$4.21	1,627,295	$3.57	$5.8	81,365	$12.63	$1.03	$2.6
2 Southwest MAAC	187,992	$27.89	$5.24	1,635,888	$3.60	$5.9	81,365	$12.63	$1.03	$1.7
3 Rest of RTO	165,816	$27.42	$4.55	1,439,915	$2.59	$3.7	81,365	$12.63	$1.03	$0.2
4 Western MAAC	180,936	$23.20	$4.20	1,575,694	$2.40	$3.8	81,365	$12.63	$1.03	$0.6
Gas CC										
1 Eastern MAAC	1,081,584	$22.51	$24.34	6,458,602	$3.57	$23.0	162,730	$12.63	$2.06	$0.7
2 Southwest MAAC	1,036,800	$27.89	$28.92	6,499,699	$3.60	$23.4	--	$12.63	$0.00	-$5.5
3 Rest of RTO	1,056,384	$27.42	$28.96	6,306,109	$2.59	$16.4	162,730	$12.63	$2.06	-$10.5
4 Western MAAC	1,048,320	$23.20	$24.32	6,256,973	$2.40	$15.0	162,730	$12.63	$2.06	-$7.2

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 10/10/2017.

C. GAS AND ELECTRIC INTERCONNECTION COSTS

Similar to the 2014 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

[101] Electricity prices were estimated following the approach discussed in Section II.B of the concurrently released VRR Curve report.

costs. We escalated the project-specific costs to 2017 dollars based on the assumed long-term inflation rate of 2.4% (see Table 12 above). We then calculated the average per-mile costs of the laterals ($4.6 million/mile) and the station costs ($3.4 million). The summary of project costs and the average per-mile pipeline cost and metering station cost are shown in Table 25.[102]

Table 25: Gas Interconnection Costs

Gas Lateral Project	State	In-Service Year	Pipeline Width *(inches)*	Pipeline Length *(miles)*	Pipeline Cost *(service year $m)*	Pipeline Cost *(2017$m)*	Pipeline Cost *($m/mile)*	Meter Station *(Y/N)*	Station Cost *(service year $m)*	Station Cost *(2017$m)*
Delta Lateral Project	PA	2010	16	3.4	$9	$11	$3	Y	$3.3	$3.8
FGT Mobile Bay Lateral Expansion	AL	2011	24	8.8	$27	$31	$4	Y	$2.4	$2.8
Northeastern Tennessee Project	VA	2011	24	28.1	$127	$147	$5	Y	$2.8	$3.2
Hot Spring Lateral Project	TX,AR	2011	16	8.4	$33	$38	$4	Y	$3.6	$4.2
Bayonne Delivery Lateral Project	NJ	2012	20	6.2	$13	$15	$2	Y	$3.8	$4.3
North Seattle Delivery Lateral Expansion	WA	2012	20	2.2	$11	$13	$6	Y	$1.4	$1.6
South Seattle Delivery Lateral Expansion	WA	2013	16	4.0	$14	$15	$4	N	n.a.	n.a.
Carty Lateral Project	OR	2015	20	24.3	$52	$55	$2	Y	$2.3	$2.4
Woodbridge lateral	NJ	2015	20	2.4	$29	$30	$13	Y	$3.5	$3.6
Western Kentucky Lateral Project	KY	2016	24	22.5	$71	$73	$3	Y	$4.8	$4.9
Rock Springs Expansion	PA,MD	2016	20	11.17	$41	$42	$4	Y	$3.3	$3.3
Average							**$4.6**			**$3.4**

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 26 below summarizes the average electrical interconnection costs of recently installed gas-fired resources that we identified as representative of the CT and 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 2017 dollars based on the assumed long-term inflation rate of 2.2% plus the additional real escalation rate for equipment of 0.2%. We then calculated the capacity-weighted average costs. We used the capacity-weighted average across all representative plants of $19.9/kW for setting the electrical interconnection of the CT and CC reference resources.

102 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 26: Electric Interconnection Costs in PJM

Plant Size	Observations	Electrical Interconnection Cost Capacity Weighted Average	
	(count)	*(2017$m)*	*(2017$/kW)*
< 500 MW	3	$4.5	$16.6
500-750 MW	4	$9.8	$14.5
> 750 MW	5	$29.7	$23.4
Capacity Weighted Average	**12**	**$21.1**	**$19.9**

Source and notes:
Confidential project-specific cost data provided by PJM.

D. 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 27.

Table 27: Current Land Asking Prices

CONE Area	Current Asking Prices		
	Observations	Range	Land Price
	(count)	*(2018$/acre)*	*(2018$/acre)*
1 EMAAC	6	$21,500 - $49,000	$36,300
2 SWMAAC	3	$58,400 - $95,100	$66,700
3 RTO	7	$6,100 - $60,300	$26,200
4 WMAAC	2	$25,000 - $63,600	$51,100

Sources and notes:
We researched land listing prices on LoopNet's Commercial Real Estate Listings (www.loopnet.com) and on LandAndFarm (www.landandfarm.com).

E. Property Taxes

Table 28 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 28: 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]
		(%)	(%)	(%)	(%)	(%)	(%)	
1 EMAAC								
New Jersey	[1]	3.8%	97.8%	3.7%	n/a	n/a	n/a	n/a
2 SWMAAC								
Maryland	[2]	1.1%	100.0%	1.1%	2.8%	50.0%	1.4%	3.3%
3 RTO								
Ohio	[3]	5.8%	35.0%	2.0%	5.8%	24.0%	1.4%	Follow annual report "SchC-NewProd (NG)"
Pennsylvania	[4]	2.5%	100.0%	2.5%	n/a	n/a	n/a	n/a
4 WMAAC								
Pennsylvania	[5]	3.6%	99.0%	3.5%	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:
http://www.state.nj.us/treasury/taxation/pdf/lpt/chap123/2017/gloucester.pdf &
http://www.gloucestercountynj.gov/depts/b/botcounty/trb.asp for Camden county see:
http://www.camdencounty.com/service/board-of-taxation/

[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:
http://dat.maryland.gov/Documents/statistics/Taxrate_July2017.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/2016%20Tax%20Rate%20Card.pdf for Carroll county see:
http://www.carrollcountyauditor.us/auditorsadvisory/Rates%20of%20Taxation%202017.pdf

[3b],[3d] Assessment ratios for real property and personal property taxes found on pages 129 and 124:
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:
http://co.lawrence.pa.us/wp-content/uploads/2014/10/2017-Sheet-for-Millage-.pdf

[4b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf
Note: Assessment ratio for calculations is capped at 100%

[4c]-[4e] According to *Pennsylvania Legislator's Municipal Deskbook (taxation & finance)* , 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:
http://www.luzernecounty.org/uploads/images/assets/county/departments_agencies/2017/2017%20Millages.pdf
http://www.lyco.org/Portals/1/TaxClaimBureau/Documents/2017%20Millage%20Rates-JULY%202017.pdf
http://www.bradfordcountypa.org/application/files/1314/9970/7556/2017_Mill_Rates.pdf

[5b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf

[5c]-[5e] According to *Pennsylvania Legislator's Municipal Deskbook (taxation & finance)* , only real estate tax assessed by local governments

F. Firm Gas Contracts

To estimate the costs of acquiring firm transportation service for SWMAAC CCs coming online in 2022, we calculated the average costs of firm gas capacity on a per-kW basis for two recent SWMAAC CCs (St. Charles and Keys Energy Center) based on rates approved by FERC in 2015. We account for the 2022 online date by escalating the reservation rates of $3.7417 per dekatherm for St. Charles and $5.4278 per dekatherm for Keys by 2.4% per year from the online plant years of 2017 (St. Charles) and 2018 (Keys) to 2022. We then calculate the total costs by multiplying the reservation rates by the amount of gas reserved by each facility per month. Next, we calculate the per-kW costs by dividing the total cost of firm gas by the net plant capacity. We calculate the total cost of firm gas reservations for the new reference resource by multiplying the average $/kW value by the net plant capacity for the SWMAAC CC reference resource. Table 29 summarizes the escalated rates and reservation for procuring firm gas service on the DCP pipeline.

Table 29: Estimated Cost of Procuring Firm Gas Service on DCP Pipeline

Component	Units	St. Charles	Keys	Reference Resource
Net Plant Capacity - Max Summer	*(MW)*	726	800	1,031
Cost of Firm Gas Capacity per Month	*(2022$ per Dth/d)*	$4.21	$5.97	$4.96
Total Firm Gas Capacity Reservation	*(Dth/d per year)*	1,584,000	1,284,000	1,952,105
Total Cost of Firm Gas Reservations	*(2022$/kW)*	$9.19	$9.58	$9.39
Total Cost of Firm Gas Reservations	***(2022$)***	**6,673,000**	**7,663,000**	**$9,676,000**

Sources and notes:
153 F.E.R.C. ¶ 61,074 (Issued October 20, 2015).
1 dekatherm (Dth) is equivalent to 1 MMBtu.

G. Operational Startup Parameters

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 30.

Table 30: Recommended Startup Parameters for Reference Resources

		CT		CC	
Parameter	Unit	Current	New	Current	New
ICAP_NOSCR	MW	392	321	n.a.	n.a.
ICAP_SCR	MW	390	348	656	1,012
NOX_RATE_NOSCR	lb/MMBtu	0.0332	0.0332	n.a.	n.a.
NOX_RATE_SCR	lb/MMBtu	0.0074	0.0093	0.0074	0.0074
SO2_RATE	lb/MMBtu	0	0.001	0	0.001
START_MMBTU	MMBtu	146.5	508.5	3,310.8	8,241.4
START_CONSUMED_MWH	MWh	0.4	0.9	10.1	12.6
START_PRODUCED_MWH	MWh	n.a.	n.a.	292.3	1074.7
START_NOX	Lb/Start	28	55	332.71	160

Appendix C: CONE Results with LTSA Costs in Fixed O&M

In the report above, we included hours-based major maintenance costs as variable O&M costs. Since June 2015, long-term major maintenance and overhaul costs that are specified in Long-Term Service Agreements (LTSAs) have been excluded from being counted as variable O&M costs in the PJM cost guidelines for cost offers.[103] We understand these guidelines are being discussed in a current initiative within the Market Implementation Committee. In case the guidelines remain unchanged, we provide a second set of O&M costs and CONE estimates below that include these costs as fixed O&M.

Since major maintenance activities and costs are spaced irregularly over the long-term, the cost in a given year represents an annual accrual for future major maintenance. For hours-based major maintenance, the fixed O&M cost is calculated based on the estimated hours-based costs of major maintenance times the expected operation of the unit in a given year. For a CC, we assume it will operate at 75% capacity factor based on the capacity factors of actual units. For the CT, we assume it will start 240 times per year based on the results of PJM's Peak-Hour Dispatch simulation for estimating the E&AS revenue offset. Removing these costs from variable O&M will increase Net E&AS revenues and offset some (or all) of the increased CONE value in the calculation of Net CONE.

Table 31 and Table 32 below summarize the O&M costs, where the LTSA costs under fixed O&M increased on average by approximately $5.6 million and $10.1 million (in 2022 dollars) for CTs and CCs, respectively.

Table 31: O&M Costs for CT Reference Resource (Alternative O&M Case)

O&M Costs	CONE Area			
	1 EMAAC *352 MW*	2 SWMAAC *355 MW*	3 Rest of RTO *321 MW*	4 WMAAC *344 MW*
Fixed O&M (2022$ million)				
LTSA, including Major Maintenance	$5.9	$5.9	$5.9	$5.9
Labor	$1.1	$1.2	$0.8	$0.9
Maintenance and Minor Repairs	$0.5	$0.5	$0.5	$0.5
Administrative and General	$0.2	$0.2	$0.2	$0.2
Asset Management	$0.5	$0.6	$0.4	$0.4
Property Taxes	$0.3	$4.1	$1.8	$0.3
Insurance	$1.9	$1.8	$1.5	$1.8
Working Capital	$0.04	$0.03	$0.03	$0.03
Total Fixed O&M (2022$ million)	**$10.4**	**$14.3**	**$11.2**	**$10.0**
Levelized Fixed O&M (2022$/MW-yr)	**$29,600**	**$40,300**	**$34,900**	**$29,000**
Variable O&M (2022$/MWh)				
Consumables, Waste Disposal, Other VOM	1.10	1.10	0.95	1.10
Total Variable O&M (2022$/MWh)	**1.10**	**1.10**	**0.95**	**1.10**

103 PJM Manual 15: Cost Development Guidelines, p. 44.

Table 32: O&M Costs for CC Reference Resource (Alternative O&M Case)

O&M Costs	CONE Area 1 EMAAC *1152 MW*	 2 SWMAAC *1160 MW*	 3 Rest of RTO *1138 MW*	 4 WMAAC *1126 MW*
Fixed O&M (2022$ million)				
LTSA, including Major Maintenance	$10.7	$10.8	$10.5	$10.4
Labor	$5.8	$6.3	$4.4	$4.6
Maintenance and Minor Repairs	$5.9	$6.1	$5.4	$5.5
Administrative and General	$1.3	$1.4	$1.1	$1.2
Asset Management	$1.6	$1.7	$1.2	$1.3
Property Taxes	$2.0	$12.3	$7.1	$1.9
Insurance	$6.0	$5.4	$5.6	$5.8
Firm Gas Contract	$0.0	$9.7	$0.0	$0.0
Working Capital	$0.1	$0.1	$0.1	$0.1
Total Fixed O&M (2022$ million)	**$33.4**	**$53.8**	**$35.4**	**$30.8**
Levelized Fixed O&M (2022$/MW-yr)	**$29,000**	**$46,400**	**$31,100**	**$27,300**
Variable O&M (2022$/MWh)				
Consumables, Waste Disposal, Other VOM	0.67	0.67	0.67	0.67
Total Variable O&M (2022$/MWh)	**0.67**	**0.67**	**0.67**	**0.67**

Table 33 and Table 34 summarize the CONE estimates where the change in LTSA costs increase CONE on average by $19,000/MW-year for CTs and $10,000/MW-year for CCs due to including the LTSA-related major maintenance costs as fixed O&M. The increase in CONE is greater than the increase in first-year fixed O&M costs (about $16,000/MW-year for CTs and $9,000/MW-year for CCs) due to the "level-nominal" levelization approach described in Section VII.A.[104] The higher CONE is likely to be offset somewhat by increases in Net E&AS revenues in the calculation of Net CONE.

104 Fixed O&M costs generally escalate year-by-year near the assumed inflation rate. The level-nominal approach for calculating CONE converts the rising costs into an annual value that remains constant in nominal terms (does not increase with inflation).

Table 33: Recommended CONE for CTs (Alternative O&M Case)

				Simple Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$316	$297	$257	$305
[2]	Installed (inc. IDC)	*$m*		$330	$310	$268	$318
[3]	First Year FOM	*$m/yr*		$10	$14	$11	$10
[4]	**Net Summer ICAP**	***MW***		**352**	**355**	**321**	**344**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$898	$836	$799	$886
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$938	$874	$835	$925
[7]	Levelized FOM	*$/kW-yr*	= [3] / [4]	$35	$43	$39	$34
[8]	**After-Tax WACC**	***%***		**7.4%**	**7.5%**	**7.4%**	**7.4%**
[9]	Effective Charge Rate	*%*		10.1%	10.1%	10.0%	10.0%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$125,300**	**$127,100**	**$118,800**	**$123,100**
	Prior Auction CONE						
[11]	PJM 2021/22 CONE	*$/MW-yr*		$133,144	$140,953	$133,016	$134,124
[12]	Escalated to 2022/23	*$/MW-yr*	= [11] x 1.028	$136,900	$144,900	$136,700	$137,900
	Difference between Updated CONE and Escalated Prior Auction CONE						
[13]	Escalated to 2022/23	*$/MW-yr*	= [10] - [12]	($11,600)	($17,800)	($17,900)	($14,800)
[14]	Escalated to 2022/23	*%*	= [13] / [12]	-8%	-12%	-13%	-11%

Sources and notes:

PJM 2021/22 parameters escalated to 2022/23 by 2.8%, based on escalation rates for individual cost components.
CONE values expressed in 2022 dollars and ICAP terms.

Table 34: Recommended CONE for CCs (Alternative O&M Case)

				Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,006	$896	$928	$961
[2]	Installed (inc. IDC)	*$m*		$1,095	$976	$1,009	$1,046
[3]	First Year FOM	*$m/yr*		$33	$54	$35	$31
[4]	**Net Summer ICAP**	***MW***		**1,152**	**1,160**	**1,138**	**1,126**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$873	$772	$815	$853
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$951	$841	$887	$929
[7]	Levelized FOM	*$/kW-yr*	= [3] / [4]	$34	$49	$34	$32
[8]	**After-Tax WACC**	***%***		**7.4%**	**7.5%**	**7.4%**	**7.4%**
[9]	Effective Charge Rate	*%*		10.6%	10.6%	10.5%	10.5%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$126,400**	**$130,600**	**$120,000**	**$122,100**
	Prior Auction CONE						
[11]	PJM 2021/22 CONE	*$/MW-yr*		$186,807	$193,562	$178,958	$185,418
[12]	Escalated to 2022/23	*$/MW-yr*	= [11] x 1.028	$192,000	$199,000	$184,000	$190,600
	Difference between Updated CONE and Escalated Prior Auction CONE						
[13]	Escalated to 2022/23	*$/MW-yr*	= [10] - [12]	($65,600)	($68,400)	($63,900)	($68,500)
[14]	Escalated to 2022/23	*%*	= [13] / [12]	-34%	-34%	-35%	-36%

Sources and notes:

PJM 2021/22 parameters escalated to 2022/23 by 2.8%, based on escalation rates for individual cost components.
CONE values expressed in 2022 dollars and ICAP terms.

Exhibit No. 3

September 26, 2018
Memo

THE Brattle GROUP

MEMORANDUM

TO: PJM

FROM: The Brattle Group

SUBJ: Impact of Sales Tax Exemption with Updated ATWACC

DATE: September 26, 2018

PJM requested that Brattle update its analysis of the Cost of New Entry (CONE) for an online date of June 1, 2022 to account for two changes: (1) recognizing that the purchase of equipment and materials for power plants is exempt from state sales taxes, as the IMM highlighted; and (2) a higher after-tax weighted average cost of capital (ATWACC) reflecting recent developments in capital markets, as summarized in Brattle's "ATWACC Update for PJM CONE Analysis" memo.[1]

Sales Tax Exemptions. Our original analysis assumed that developers would need to pay sales tax in each of the four states where the reference resources are located (New Jersey, Pennsylvania, Maryland, and Ohio). However, recent inquiries from PJM's Independent Market Monitor (IMM) and further research revealed that equipment and materials are exempt from state sales tax.[2] To reflect such exemptions, we removed sales tax on equipment and materials for all CONE areas. These changes decreased the CT CONE by $3,475/MW-year (a 3.3% decrease) on average across the four CONE areas and the CC CONE by $3,475/MW-year (a 3.0% decrease) on average.

Higher ATWACC. As explained in Brattle's ATWACC memo, the ATWACC increased from 7.5% to 8.0%, with a 55% debt / 45% equity capital structure, 5.5% cost of debt, and 13.0% cost of equity.[3] The 0.5% increase in ATWACC increased the CT CONE on average by $3,875/MW-year (a 3.7% increase) and the level-nominal CC CONE on average by $4,450/MW-year (a 3.9% increase).

The rest of this memo displays the CONE tables with the changes in the sales tax exemption and updated ATWACC of 8.0%. Each table's title corresponds to the table in the original CONE study.

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[1] See "ATWACC Update for PJM CONE Analysis," submitted by Brattle to PJM on August 21, 2018.

[2] The states of New Jersey, Pennsylvania, Maryland, and Ohio are exempt from sales tax for equipment and materials used in the production of electricity.

[3] See "ATWACC Update for PJM CONE Analysis" memo.

Table ES-1: Updated 2022/2023 CONE Values

	Simple Cycle ($/ICAP MW-year)				Combined Cycle ($/ICAP MW-year)			
	EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
2021/22 Auction Parameter	$133,144	$140,953	$133,016	$134,124	$186,807	$193,562	$178,958	$185,418
...Escalated to 2022/23	$136,900	$144,900	$136,700	$137,900	$192,000	$199,000	$184,000	$190,600
Updated 2022/23 CONE	**$106,800**	**$108,600**	**$98,600**	**$104,400**	**$117,100**	**$120,900**	**$110,700**	**$113,000**
Difference from Prior CONE	-22%	-25%	-28%	-24%	-39%	-39%	-40%	-41%

Sources and notes:

All monetary values are presented in nominal dollars.

2021/22 auction parameter values based on Minimum Offer Price Rule (MOPR) Floor Offer Prices for 2021/22 BRA.

PJM 2021/22 parameters escalated to 2022/23 by 2.8%, based on S&L analysis of escalation rates for materials, turbine, and labor costs.

CONE includes major maintenance costs in variable O&M costs. Alternative values with major maintenance costs in fixed O&M costs are presented in Appendix C.

Table ES-2: Estimated CT CONE for 2022/2023

		Simple Cycle			
		EMAAC	SWMAAC	Rest of RTO	WMAAC
Net Summer ICAP	*MW*	352	355	321	344
Overnight Costs	*$/kW*	$864	$806	$771	$853
Effective Charge Rate	*%*	10.5%	10.5%	10.5%	10.5%
Plant Costs	*$/MW-yr*	$91,000	$85,000	$81,000	$89,800
Fixed O&M	*$/MW-yr*	$15,800	$23,600	$17,600	$14,600
Levelized CONE	***$/MW-yr***	**$106,800**	**$108,600**	**$98,600**	**$104,400**
Levelized CONE	***$/MW-day***	**$293**	**$298**	**$270**	**$286**

Notes: CONE values expressed in 2022 dollars and Installed Capacity (ICAP) terms

Table ES-3: Estimated CC CONE for 2022/2023

		Combined Cycle			
		EMAAC	SWMAAC	Rest of RTO	WMAAC
Net Summer ICAP	*MW*	1,152	1,160	1,138	1,126
Overnight Costs	*$/kW*	$842	$745	$785	$823
Effective Charge Rate	*%*	11.1%	11.1%	11.1%	11.1%
Plant Costs	*$/MW-yr*	$93,600	$83,000	$87,200	$91,400
Fixed O&M	*$/MW-yr*	$23,500	$37,900	$23,500	$21,600
Levelized CONE	***$/MW-yr***	**$117,100**	**$120,900**	**$110,700**	**$113,000**
Levelized CONE	***$/MW-day***	**$321**	**$331**	**$303**	**$310**

Notes: CONE values expressed in 2022 dollars and ICAP terms.

Table 1: Plant Capital Costs for CT Reference Resource
in Nominal $ for 2022 Online Date

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*352 MW*	*355 MW*	*321 MW*	*344 MW*
Owner Furnished Equipment				
Gas Turbines	$74.4	$74.4	$74.4	$74.4
HRSG / SCR	$26.6	$26.6	$0.0	$26.6
Sales Tax	$0.0	$0.0	$0.0	$0.0
Total Owner Furnished Equipment	**$101.0**	**$101.0**	**$74.4**	**$101.0**
EPC Costs				
Equipment				
Other Equipment	$25.7	$25.6	$28.5	$25.7
Construction Labor	$43.5	$31.8	$31.0	$37.6
Other Labor	$16.5	$15.3	$12.9	$16.0
Materials	$6.6	$6.5	$6.5	$6.6
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	$19.3	$18.0	$15.3	$18.7
EPC Contingency	$21.3	$19.8	$16.9	$20.6
Total EPC Costs	**$132.8**	**$116.9**	**$111.1**	**$125.1**
Non-EPC Costs				
Project Development	$11.7	$10.9	$9.3	$11.3
Mobilization and Start-Up	$2.3	$2.2	$1.9	$2.3
Net Start-Up Fuel Costs	$2.6	$1.7	$0.2	$0.6
Electrical Interconnection	$7.8	$7.8	$7.1	$7.6
Gas Interconnection	$29.1	$29.1	$29.1	$29.1
Land	$0.4	$0.7	$0.3	$0.5
Fuel Inventories	$3.0	$3.0	$2.7	$2.9
Non-Fuel Inventories	$1.2	$1.1	$0.9	$1.1
Owner's Contingency	$4.6	$4.5	$4.1	$4.4
Financing Fees	$7.7	$7.3	$6.3	$7.4
Total Non-EPC Costs	**$70.4**	**$68.2**	**$61.8**	**$67.3**
Total Capital Costs	**$304.2**	**$286.2**	**$247.3**	**$293.4**
Overnight Capital Costs ($million)	**$304**	**$286**	**$247**	**$293**
Overnight Capital Costs ($/kW)	**$864**	**$806**	**$770**	**$853**
Installed Cost ($/kW)	**$906**	**$845**	**$807**	**$894**

Table 2: Plant Capital Costs for CC Reference Resource in Nominal $ for 2022 Online Date

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*1152 MW*	*1160 MW*	*1138 MW*	*1126 MW*
Owner Furnished Equipment				
Gas Turbines	$173.2	$167.5	$173.2	$173.2
HRSG / SCR	$55.4	$53.6	$55.4	$55.4
Sales Tax	$0.0	$0.0	$0.0	$0.0
Total Owner Furnished Equipment	**$228.6**	**$221.1**	**$228.6**	**$228.6**
EPC Costs				
Equipment				
Condenser	$5.8	$5.8	$5.8	$5.8
Steam Turbines	$47.1	$45.5	$47.1	$47.1
Other Equipment	$74.7	$72.1	$74.7	$74.7
Construction Labor	$211.1	$159.3	$167.4	$187.2
Other Labor	$56.5	$50.6	$52.5	$54.3
Materials	$51.5	$51.2	$51.5	$51.5
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	$67.5	$60.6	$62.8	$64.9
EPC Contingency	$74.3	$66.6	$69.0	$71.4
Total EPC Costs	**$588.6**	**$511.8**	**$530.8**	**$556.9**
Non-EPC Costs				
Project Development	$40.9	$36.6	$38.0	$39.3
Mobilization and Start-Up	$8.2	$7.3	$7.6	$7.9
Net Start-Up Fuel Costs	$0.8	-$5.5	-$10.5	-$7.2
Electrical Interconnection	$25.5	$25.6	$25.2	$24.9
Gas Interconnection	$29.1	$29.1	$29.1	$29.1
Land	$1.5	$2.7	$1.0	$2.0
Fuel Inventories	$6.9	$0.0	$6.8	$6.7
Non-Fuel Inventories	$4.1	$3.7	$3.8	$3.9
Owner's Contingency	$9.3	$8.0	$8.1	$8.5
Emission Reduction Credit	$2.2	$2.2	$2.2	$2.2
Financing Fees	$24.6	$21.9	$22.6	$23.5
Total Non-EPC Costs	**$152.9**	**$131.6**	**$133.8**	**$140.8**
Total Capital Costs	**$970.1**	**$864.5**	**$893.2**	**$926.4**
Overnight Capital Costs ($million)	**$970**	**$865**	**$893**	**$926**
Overnight Capital Costs ($/kW)	**$842**	**$745**	**$785**	**$823**
Installed Cost ($/kW)	**$922**	**$816**	**$859**	**$901**

Table 3: O&M Costs for CT Reference Resource

O&M Costs	CONE Area 1 EMAAC *352 MW*	2 SWMAAC *355 MW*	3 Rest of RTO *321 MW*	4 WMAAC *344 MW*
Fixed O&M (2022$ million)				
LTSA	$0.3	$0.3	$0.3	$0.3
Labor	$1.1	$1.2	$0.8	$0.9
Maintenance and Minor Repairs	$0.5	$0.5	$0.5	$0.5
Administrative and General	$0.2	$0.2	$0.2	$0.2
Asset Management	$0.5	$0.6	$0.4	$0.4
Property Taxes	$0.3	$3.9	$1.8	$0.3
Insurance	$1.8	$1.7	$1.5	$1.8
Working Capital	$0.03	$0.03	$0.03	$0.03
Total Fixed O&M (2022$ million)	**$4.7**	**$8.5**	**$5.4**	**$4.3**
Levelized Fixed O&M (2022$/MW-yr)	**$13,400**	**$23,800**	**$16,900**	**$12,400**
Variable O&M (2022$/MWh)				
Consumables, Waste Disposal, Other VOM	1.10	1.10	0.95	1.10
Total Variable O&M (2022$/MWh)	**1.10**	**1.10**	**0.95**	**1.10**
Major Maintenance - Starts Based ($/factored start, per turbine)	**23,464**	**23,464**	**23,464**	**23,464**

Table 4: O&M Costs for CC Reference Resource

O&M Costs	CONE Area 1 EMAAC *1152 MW*	2 SWMAAC *1160 MW*	3 Rest of RTO *1138 MW*	4 WMAAC *1126 MW*
Fixed O&M (2022$ million)				
LTSA	$0.5	$0.5	$0.5	$0.5
Labor	$5.8	$6.3	$4.4	$4.6
Maintenance and Minor Repairs	$5.9	$6.1	$5.4	$5.5
Administrative and General	$1.3	$1.4	$1.1	$1.2
Asset Management	$1.6	$1.7	$1.2	$1.3
Property Taxes	$2.0	$11.7	$6.9	$1.9
Insurance	$5.8	$5.2	$5.4	$5.6
Firm Gas Contract	$0.0	$9.7	$0.0	$0.0
Working Capital	$0.1	$0.1	$0.1	$0.1
Total Fixed O&M (2022$ million)	**$23.0**	**$42.8**	**$25.0**	**$20.7**
Levelized Fixed O&M (2022$/MW-yr)	**$20,000**	**$36,900**	**$22,000**	**$18,400**
Variable O&M (2022$/MWh)				
Major Maintenance - Hours Based	1.44	1.44	1.44	1.44
Consumables, Waste Disposal, Other VOM	0.67	0.67	0.67	0.67
Total Variable O&M (2022$/MWh)	**2.11**	**2.11**	**2.11**	**2.11**

Table 5: Recommended CONE for CT Plants in 2022/2023

				Simple Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$304	$286	$247	$293
[2]	Installed (inc. IDC)	*$m*		$319	$300	$259	$307
[3]	First Year FOM	*$m/yr*		$5	$8	$5	$4
[4]	**Net Summer ICAP**	***MW***		**352**	**355**	**321**	**344**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$864	$806	$770	$853
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$906	$845	$807	$894
[7]	Levelized FOM	*$/kW-yr*	= [3] / [4]	$16	$24	$18	$15
[8]	**After-Tax WACC**	***%***		**8.0%**	**8.0%**	**7.9%**	**7.9%**
[9]	Effective Charge Rate	*%*		10.5%	10.5%	10.5%	10.5%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$106,800**	**$108,600**	**$98,600**	**$104,400**
	Prior Auction CONE						
[11]	PJM 2021/22 CONE	*$/MW-yr*		$133,144	$140,953	$133,016	$134,124
[12]	Escalated to 2022/23	*$/MW-yr*	= [11] x 1.028	$136,900	$144,900	$136,700	$137,900
	Difference between Updated CONE and Escalated Prior Auction CONE						
[13]	Escalated to 2022/23	*$/MW-yr*	= [10] - [12]	($30,100)	($36,300)	($38,100)	($33,500)
[14]	Escalated to 2022/23	*%*	= [13] / [12]	-22%	-25%	-28%	-24%

Sources and notes:

PJM 2021/22 parameters escalated to 2022/23 at 2.8% annually, based on S&L analysis of escalation rates for materials, turbine and labor costs.

CONE values expressed in 2022 dollars and ICAP terms.

Table 6: Recommended CONE for CC Plants in 2022/2023

				Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$970	$865	$893	$926
[2]	Installed (inc. IDC)	*$m*		$1,062	$947	$978	$1,014
[3]	First Year FOM	*$m/yr*		$23	$43	$25	$21
[4]	**Net Summer ICAP**	***MW***		**1,152**	**1,160**	**1,138**	**1,126**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$842	$745	$785	$823
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$922	$816	$859	$901
[7]	Levelized FOM	*$/kW-yr*	= [3] / [4]	$24	$38	$24	$22
[8]	**After-Tax WACC**	***%***		**8.0%**	**8.0%**	**7.9%**	**7.9%**
[9]	Effective Charge Rate	*%*		11.1%	11.1%	11.1%	11.1%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$117,100**	**$120,900**	**$110,700**	**$113,000**
	Prior Auction CONE						
[11]	PJM 2021/22 CONE	*$/MW-yr*		$186,807	$193,562	$178,958	$185,418
[12]	Escalated to 2022/23	*$/MW-yr*	= [11] x 1.028	$192,000	$199,000	$184,000	$190,600
	Difference between Updated CONE and Escalated Prior Auction CONE						
[13]	Escalated to 2022/23	*$/MW-yr*	= [10] - [12]	($74,900)	($78,100)	($73,300)	($77,600)
[14]	Escalated to 2022/23	*%*	= [13] / [12]	-39%	-39%	-40%	-41%

Sources and notes:

PJM 2021/22 parameters escalated to 2022/23 at 2.8% annually, based on S&L analysis of escalation rates for materials, turbine and labor costs.

CONE values expressed in 2022 dollars and ICAP terms.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. **)** **Docket No. ER19-___-000**

VERIFICATION

Samuel A. Newell, being first duly sworn, deposes and states that he is the Samuel A. Newell referred to in the foregoing document entitled "Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

Subscribed and sworn to before me, the undersigned notary public, this 12th day of October 2018.

Debra A. Paolo

Notary Public

My Commission expires: Sep. 4, 2020

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Docket No. ER19-___-000**

VERIFICATION

John M. Hagerty, being first duly sworn, deposes and states that he is the John M. Hagerty referred to in the foregoing document entitled "Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

J Michael Hagerty

Subscribed and sworn to before me, the undersigned notary public, this 11 day of October 2018.

____
Notary Public

My Commission expires: 1/1/2021

NICHOLE HEATH
NOTARY PUBLIC
DISTRICT OF COLUMBIA
Expiration Jan 1, 2021

{W0173056.2 }

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Docket No. ER19-___-000**

VERIFICATION

Sang H. Gang, being first duly sworn, deposes and states that he is the Sang H. Gang referred to in the foregoing document entitled "Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

Sang H. Gang

State of Illinois
County of Cook

Subscribed and sworn to before me, the undersigned notary public, this 11th day of October 2018.

Belinda Drygalski
Notary Public

My Commission expires: 09/14/2022

OFFICIAL SEAL
BELINDA DRYGALSKI
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:09/14/22

<u>**Attachment F**</u>

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. ER19-_____-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, and 2014.

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 and 2014.

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 2017 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 ("EAS Offset"). We participated in the development of the CONE estimate and co-authored the report, "PJM Cost of New Entry: Combustion Turbines and Combined Cycle Plants with June 1, 2022 Online Date" ("2018 CONE Study"), a copy of which is attached to the affidavit of Dr. Newell, Mr. Hagerty, and Mr. Gang.

6. Specifically, we were responsible for the ATWACC estimate, including the capital structure and estimated costs of debt and equity, presented in the 2018 CONE Study. 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 ("NPV") 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 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. We believe that 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 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. Finally, we made an upward adjustment to the ATWACC for the reduction of the federal corporate income tax rate from 35% to 21%, enacted at the end of 2017.

7. In the 2018 CONE Study, completed in April, 2018, we estimated that the ATWACC for the new entry plant would be 7.5%. We updated that estimate in August 2018, and found increases (relative to the earlier estimate) in both the U.S. risk-free rate and the cost of debt. As set forth in a memo provided to PJM and PJM stakeholders dated August 21, 2018, we estimated that the ATWACC for the new entry plant has increased to 8.0%. (A copy of that memo (the "August 21 Supplement") is shown in Exhibit No. 2 to our affidavit.) Our recommended financing components consistent with this overall recommended ATWACC are a debt ratio of 55%, an equity ratio of 45%, a cost of debt of 5.5%, and a cost of equity of 13.0%. The analytical framework, supporting data, and rationales for these recommendations are fully set forth in the 2018 CONE Study and August 21 Supplement, both of which (insofar as they address the cost of capital), were prepared by us or under our supervision and direction.

8. PJM, based in a large part on our 8.0% recommendation and additional input from merchant generators, made a final recommendation of an 8.2% ATWACC to its stakeholders, adopting a higher cost of debt of 6.0%. We note that our 8.0% recommendation is within the upper end, but not at the very top of the range of the

comparable company results. To adjust for the tax law changes and recent interest rate increases, the highest two discount rates (ATWACC) used by financial advisors in recent M&A transactions would increase by about 1% to above 8.3%. The 1% impact is based on the cumulative adjustment we have made to our December 2017 ATWACC: 8% (Brattle August 2018 Recommendation) less 7% (ATWACC for PJM before tax law changes in December 2017). While above our estimate, PJM's 8.2% ATWACC recommendation is within the range of available market evidence for merchant generation.

9. This concludes our affidavit.

Exhibit No. 1

Johannes P. Pfeifenberger and Bin Zhou Qualifications

JOHANNES P. PFEIFENBERGER

Principal

Boston, MA +1.617.864.7900 Hannes.Pfeifenberger@brattle.com

Mr. Johannes Pfeifenberger is an economist with a background in electrical engineering and twenty 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. As a member of The Brattle Group's Utility Regulation and Electric Power practices, he specializes in:

- *Electricity market design and restructuring policies*
- *Transmission pricing and cost-benefit analyses*
- *Strategy and planning*
- *Analysis and mitigation of market power*
- *Storage and Generation Asset valuation*
- *Ratemaking and incentive regulation*
- *Contract disputes and commercial damages*

On behalf of his clients—which includes investor-owned utilities, independent system operators, transmission companies, public power agencies, industry groups, large industrial customers, and generators across North America—Mr. Pfeifenberger has facilitated strategic planning efforts and assisted them in a range of subject areas, including resource adequacy, ISO/RTO market design, transmission planning, the reasons behind rate increases, the implications of restructuring policies, and the value of assets and contracts. He has also helped clients explore the benefits of alternative regulation, the desirability of settlement proposals, and the need for regulatory and legislative actions in the context of evolving market conditions.

He is retained frequently by counsel to provide litigation support, including the formulation of economic arguments and assistance with discovery, depositions, and cross examination. He has experience in identifying and coordinating expert witnesses and in drafting legal documents involving economic subject areas or highly technical industry matters.

Prior to joining The Brattle Group, Mr. Pfeifenberger was a consultant with Cambridge Energy Research Associates in Cambridge, Massachusetts, where he modeled and analyzed U.S. regional electricity supply, fuel demand, sensitivity of peak-load electricity demand, and short-term fuel substitution. He previously served as a research assistant at the University of Technology in Vienna, Austria, where he contributed to the development of a supra-regional generation dispatch and expansion planning model in cooperation with the IBM Research Group. During his studies he also worked at Dow Corning, Siemens Austria, and a utility company in Salzburg, Austria.

EDUCATION

Mr. Pfeifenberger received an M.A. in economics and finance from Brandeis University and an M.S. ("Diplom Ingenieur") in electrical engineering, with a specialization in power engineering and energy economics, from the University of Technology in Vienna, Austria.

PROJECT EXPERIENCE

Market Design and Restructuring Policies

- **Energy Market Imbalance and Flexibility Design.** Worked with CAISO to simulate alternative dispatch options and emissions accounting for the western Energy Imbalance Market (EIM). Assisted CAISO in diagnosing system flexibility challenges and developing a framework for addressing the identified challenges.
- **Alberta Capacity Market Design.** Advised and closely worked with AESO staff on the design of a proposed forward capacity market for Alberta.
- **Ontario Capacity Market Design.** Advised and closely worked with IESO staff on the design of a proposed forward capacity market for Ontario.
- **Alternative Retail Power Procurement and Cost Recovery Frameworks.** For a group of utilities facing load departures through community choice aggregation, distributed energy resources, and energy efficiency initiative, reviewed alternative power procurement and cost recovery options in North American jurisdictions. Developed integrated frameworks that can fairly allocate between departing and remaining loads the cost of existing resources procured to meet state public-policy mandates while procuring new resources to meet such mandates.
- **Analysis of Regional Market Alternatives for the Mountain West Transmission Group.** For the eight members of the Mountain West Transmission Group in Colorado, Wyoming, and neighboring states analyzed (1) the implications on member transmission costs of different regional transmission tariff options; and (2) the costs and benefits of alternative regional transmission and market options. The regional transmission and market analysis included detailed market simulations and estimation of member costs and benefits for (a) retaining the current bilateral market construct; (b) forming a regional transmission group with de-pancaked transmission service; and (c) forming or joining a full "Day 2" regional wholesale power market. The results informed the clients decision to explore regional market alternatives with CAISO, PJM, and SPP, which ultimately resulted in a commitment to join SPP.
- **Benefits of Updating Ontario's Wholesale Market Design.** For the Ontario Independent System Operator, estimated the likely benefit of Market Renewal efforts to update the design of Ontario's energy market, improve system flexibility and operability, introduce an incremental capacity market, and increase the efficiency and utilization of the Province's

interties with neighboring power markets. Worked with IESO staff, the Market Renewal Working Group, the Market Surveillance Panel, and IESO stakeholders to document inefficiencies of the current market design and develop the framework for estimating Market Renewal benefits and implementation costs taking into consideration Ontario unique market structure, energy policy environment, and resource mix.

- **Benefits and Costs of a Regional Western Power Market.** For the California ISO, led a team of multiple consulting companies in: (a) analyzing the impact of transitioning Western Interconnection into a locational marginal cost-based full "Day-2" energy market with centralized optimized day-ahead unit commitment and real-time dispatch, including how such a market would help integrate large amounts of variable renewable generation across the Western Interconnection; (b) reporting the results to stakeholder groups across the West and government representatives about the methodology and findings of the analyses; (c) reporting the findings of other regional markets that have gone through similar or parallel transisions; and (d) authoring public report that includes detailed descriptions of methodologies, analyses, findings, and references to other studies reviewed in conducting the quantitative and qualitative analyses of the benefits and costs of a western regional market. This effort identified and reviewed two dozen ex-post and ex-anti industry studies of regional-market related impacts, including the costs and benefits of transitioning from zonal to nodal market design and migrating from an real-time imbalance market to a full day-ahead market with optimized unit commitments and ancillary services markets.

- **Benefits of Regional Market Participation**. For Western Areas Power Administration (WAPA), Basin Electric, and Heartland Rural Electric Cooperative, evaluated the costs and benefits of remaining as a standalone system compared to regional market participation in either the Southwest Power Pool (SPP) or MidContinent Independent System Operator (MISO). The effort included detailed market simulations of the three alternatives, which informed the clients' choice to join SPP. **Characteristics of Successful Capacity Markets.** Discussed experience with and characteristics of successful capacity markets at the international Association of Power Exchanges meeting, at the Ontario IESO's stakeholder summit, and with the IESO staff, executives, and Board members in support of the IESO's long-term strategic planning effort.

- **Designing Demand Curves for Capacity Markets.** For PJM, analyzed the performance of its current demand curve and that of alternative demand curve designs in terms of the curves ability to support meeting resource adequacy target and mitigate price volatility at both the system-wide and zonal levels.

- **Evaluation of energy-only and capacity market designs.** For ERCOT, analyzed economically-optimal reserve margins, resource adequacy level achieved by current energy-only market design, and tradeoffs between reliability, costs and risks of implementing a mandatory resource adequacy requirement and a centralized capacity market.

- **Determination of Resource Adequacy Targets.** Surveyed range of methodologies used by system operators to determine resource adequacy targets, and documented variations in application of the 1-day-in-10-years criteria and calculation of target reserve margins. Analyzed economically-optimal planning reserve margins for a realistic but hypothetical region in comparison to margins based on the 1-in-10 criteria and as a function of transmission interties with neighboring regions, demand-response and renewables penetration, and different generation technology costs. Evaluated the implications of different standards from a customer cost, societal cost, risk mitigation, market structure, and market design perspective. Documented uncertainty and gaps in investment cost recovery at different levels of planning reserve margin targets.

- **Review of Resource Adequacy in Energy-Only Markets.** For ERCOT, reviewed and documented resource adequacy concerns, generation investment challenges, and options to improve resource adequacy. For Alberta Electric System Operator, updated review of resource adequacy challenges and ability of its energy-only market to maintain generation investment signals and assure long-term resource adequacy.
- **Review of Intertie Operations and Planning Practices.** For operator of an energy-only wholesale power market analyzed North American and European practices with respect to (1) availability and granting of transmission rights over interties with neighboring markets; (2) efficient scheduling practices for available intertie capacity; (3) resource adequacy implications of expanding interties between an energy-only market and neighboring traditionally-regulated markets or markets with mandated resource requirements; and (4) planning and cost allocation of intertie expansion projects. Developed market design options with discussion of their advantages and disadvantages for considerations by the system operator.
- **Review of PJM Capacity Market.** Undertook second tri-annual review of the Reliability Pricing Model. Analyzed capacity auction results and response to market fundamentals. Interviewed stakeholders and documented concerns. Addressed key market design elements and recommended improvements to reduce pricing uncertainty, safeguard future performance, and address mitigation of capacity market bids. Updated cost of new entry analysis for combustion turbine and combined cycle plants.
- **Market Design for Renewables Integration.** For the Alberta Electric System Operator reviewed international experience with adjusting energy, capacity and ancillary service market designs to facilitate integration of intermittent renewable resources.
- **Russian Capacity and Natural Gas Market Liberalization.** Reviewed on behalf of a market participant market design, regulatory uncertainty, and liberalization success. Focused 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.
- **Resource Adequacy in Energy-Only Market.** For the Alberta Electric System Operator analyzed the likely ability of its energy-only market to assure long-term resource adequacy. Identified challenges to resource adequacy and analyzed ability of the market design to support the retention of existing and entry of new resources in light of these challenges.

- **Role of Demand Response in Energy-Only Market.** For the Alberta Electric System Operator analyzed the role and potential of demand response in its energy-only market. Developed recommendations to facilitate growth of efficient demand response.
- **Capacity and Energy Market Design Alternatives.** For PJM, prepared whitepaper comparing the PJM Reliability Pricing Model ("RPM") with alternative power market designs and evaluates each design's ability to maintain resource adequacy, summarize relevant U.S. and international experience, and discuss the advantages and disadvantages of the various approaches.
- **RTO Capacity Market Design.** For PJM, undertook an independent evaluation of its Reliability Pricing Mechanism (RPM). Analyzed and documented performance of RPM, design features, and potential entry barriers. Presented conclusions and design recommendations to PJM and its stakeholders.
- **ISO Market Design Alternatives.** For a utility and industrial customer group in New England, reviewed and evaluated alternative market designs to provide ISO functionality. On behalf of state legislature and for filing with the state regulatory commission, prepared detailed report on the design, advantages, and disadvantages of an "independent system administrator" framework as alternative to ISO participation.
- **RTO Cost-Benefit Analysis.** For the Midwest ISO, examined and responded to analyses of costs and benefits associated with a utility's RTO membership alternatives. Analyzed reasonableness of assumptions and results of market simulations, supervised simulations of other scenarios, and testified before state regulatory commission.
- **RTO Configuration.** Analyzed and submitted testimony on the financial and operational harm of two utilities' RTO choice on Michigan and Wisconsin. Documented observed market conditions, simulated Midwestern and Eastern power markets under alternative RTO configurations, evaluated economic hurdles across the RTO, and evaluated mitigation of seam-related impacts through inter-RTO coordination.
- **Restructuring Retail Rate and Generation Cost Assessment.** For a New England client, assessed retail rate trends in comparison to regional and U.S. averages. Analyzed cost of new generation facilities, including renewables, and the extent to which adding wind resources would affect retail rates under alternative short- and long-term purchased power contractual structures.
- **RTO Tariff Design.** Supported a RTO with the design and regulatory filing of tariff schedules for recovery of energy market and congestion management administrative costs. Submitted testimony evaluating the reasonableness of the proposed new tariff schedules from an economic perspective.
- **RTO Design and Configuration.** Analyzed the configuration and effectiveness of proposed independent system operators (ISOs) and RTOs in a number of assignments: supported counsel in drafting transmission entities' RTO filings; evaluated whether proposed RTOs satisfied the economic requirements set out in FERC Order No. 2000; analyzed the efficiency

and policy implications of proposed changes in RTO membership; worked with clients to refine a structural approach to inter-RTO coordination of various transmission functions; and developed economic principles to evaluate the relationship between an ISO's geographic scope and configuration and its ability to facilitate non-discriminatory transmission access and competition in wholesale power markets.

- **Restructuring Policy.** Assessed restructuring approaches in the German electric power industry. Reviewed and responded to proposals regarding cost of service principles, cost allocation, transmission pricing, and necessary regulatory frameworks to ensure fair transmission access and prevent anti-competitive discrimination by vertically-integrated incumbents.
- **Impact of Industry Restructuring.** For a California utility, analyzed the impacts of the California Public Utilities Commission's restructuring proposal on utility investors and the utility's required rate of return. Drafted testimony, supervised the empirical analyses supporting the expert witness, responded to data requests, and prepared cross-examination of opposing witnesses.
- **Industry Restructuring.** On the invitation of the Chairman of the Subcommittee on Telecommunications and Finance (U.S. House of Representatives, Committee on Commerce), submitted written testimony in the oversight hearing on the subject of the restructuring of the international satellite organizations.
- **Privatization.** Analyzed the economic implications associated with a house bill targeted at privatization of the international satellite organization. Coauthored the review of a study attempting to quantify the bill's impact on U.S. users.
- **Regulatory Relief.** On behalf of a U.S. international service carrier, performed and submitted to the Federal Communications Commission a study analyzing the economic basis for the client's reclassification as a non-dominant carrier; examined competitive market forces and the efficiency implications of asymmetric regulation; and participated in meetings with the FCC's staff and chief economist.

Transmission Pricing and Cost Benefit Analysis

- **Benefit of Large Generation Tie Line to Integrate Wind Generation.** For American Electric Power, developed a market simulation and benefit-cost framework to quantify the benefits of integrating the proposed 2,000 MW Wind Catcher generating plant through a 765 kV generation tie line from the wind-rich Oklahoma Panhandle region to the Tulsa load center. Quantified congestion and marginal loss benefits, impact on AEP load and generation prices, and costs compared to acquiring a similar amount of wind generation through traditional procurement options. Assisted AEP in integrating these analyses into its company-specific resource planning framework for presentation to state regulatory commissions.
- **Off-shore Transmission Networks.** For independent transmission developer researched advantages and disadvantages of alternative transmission solutions to integrate proposed off-

shore wind developments. Documented experience in Europe with generator-owned individual tie lines and independently-developed transmission solutions, including off-shore grids capable of integrating multiple off-shore wind projects.

- **HVDC Supergrids.** For large private investor, prepared detailed briefing materials discussing and documenting the benefits, costs, permitting, and regulatory and public policy challenges of developing large HVDC supergrids in the U.S., Europe, and China.
- **International Submarine HVDC Cable Development.** Assisted ITC in due diligence effort of developing the Lake Erie Connector between Ontario and PJM. Developed value proposition and currently conducting the open solicitation process subject to FERC regulatory guidelines.
- **Interregional Planning and Cost Allocation.** Supported the Southwest Power Pool and its Regional State Committee in their efforts to develop planning approaches, cost allocation principles, metrics, and evaluation frameworks for interregional transmission projects.
- **Benefits of Offshore HVDC Transmission Network.** Analyzed costs and benefits of a proposed offshore transmission network compared to alternative transmission solutions. Evaluated public policy and reliability benefits, cost reductions and risk mitigation of offshore wind power developments through streamlined permitting processes and economies of scale, employment and economic stimulus benefits to the local economy, and electricity market impacts, including congestion relief, energy and capacity market benefits, and renewables integration cost advantages.
- **Due-diligence Support for Acquisition of a Transmission Company.** For a group of investors, supported an extensive due-diligence effort in their attempt to acquire a transmission company. Evaluated the size, financial impact, and the potential regulatory risks of the transmission company's large capital expansion plan under a range of future scenarios.
- **Scenario-based Transmission Planning to Address Long-term Uncertainties.** For the Electric Reliability Council of Texas (ERCOT), facilitated ERCOT staff and stakeholder sessions for developing scenarios of a wide range of plausible futures for use in ERCOT's long-term transmission planning effort.
- **Long-term Transmission Planning Process.** As part of an U.S. Department of Energy supported effort, reviewed ERCOT's long-term transmission planning process, obtained stakeholder input, and developed recommendations for improving the scope and effectiveness of the planning process. Facilitated stakeholder-based scenario building effort to support ERCOT long-term transmission planning effort.
- **Best Practices in Transmission Benefit Determination**. For the WIRES Group, reviewed practices related to identification and estimation of transmission benefits by U.S. regional transmission planning entities. Developed "checklist" of transmission-related benefits and summarized best-practice experience in considering and estimating them.
- **Benefit of Broad-based Transmission Planning.** For independent transmission company prepared testimony on benefits of broad-based, independent planning for proposed acquisition of transmission assets. Applied broad-based planning perspective to develop and

evaluate a proposed portfolio of strategic transmission projects that would provide a broad set of reliability, economic, and public policy benefits to the region.

- **Interregional Cost Allocation.** Supported the Southwest Power Pool and its Regional State Committee in their efforts to develop cost allocation principles, metrics, and evaluation frameworks for interregional transmission projects.
- **Benefits of New 765kV Transmission Line.** Analyzed renewable integration and congestion relief benefit of proposed $1.2 billion transmission line in western PJM.
- **Benefits of Regional Transmission Overlay.** Analyzed public policy benefits, reliability and congestion relief benefits, and economic benefit of EHV transmission overlay in the Midwest. Analyzed renewable investment cost savings, production and emission cost savings, transmission loss reduction, insurance benefits during extreme contingencies and market conditions, capacity and reserve margin benefits, competition and liquidity benefits, fuel diversity and resource planning flexibility benefits, and jobs and economic stimulus benefits.
- **Jobs and Economic Benefits of Transmission and Wind Investments.** Analyzed state-level employment and economic stimulus benefits of regional transmission and wind generation investments in the Midwest and Southwest.
- **Evaluation of Alternative Transmission Rate Design and Cost Allocation Proposals.** Supported the Midwest ISO in the evaluation of alternative transmission and generator interconnection cost allocation methodologies. Undertaken in coordination with the "Cost Allocation and Regional Planning" effort of the Organization of Midwest ISO States.
- **Analysis of HVDC Submarine Cable Benefits.** Developed and implemented framework for quantification of economic benefits of HVDC submarine cable, including market price impacts, production cost and congestion-relief savings, and the line's merchant value. Described additional, difficult-to-quantify benefits related to reliability, wind integration, ancillary services, and system operations.
- **Analysis of Transmission Congestion and Benefits.** Analyzed the impacts on transmission congestion, California benefits, and Arizona utility impacts of a proposed inter-state transmission line. Simulated congestion and power market conditions in 2013 and 2020 considering the recent changes in economic and fuel market conditions, and increased renewable generation requirements throughout the Western Electricity Coordination Council region.
- **Transmission Cost Allocations.** For utility and industrial customers, determined alternative methodologies to allocate RTO transmission costs and analyzed the cost implications of alternative allocations of investments.
- **Independent Transmission Project Evaluation.** Analyzed for an independent transmission company the economic benefit and needs for a submarine HVDC cable. Addressed needs from resource adequacy, renewable resources and greenhouse gas, resource diversity, and local reliability perspective. Evaluated various regional and local economic benefits.

- **Transmission Siting Case and Cost-Benefit Study.** Testified in a state siting case to present the regional context for a major proposed transmission line and explained the results of market simulation studies. Analyzed impact of transmission line on the state's generation costs, wholesale power market, and natural gas market. Discussed and quantified transmission-related benefits.
- **Transmission Cost-Benefit Study.** Worked with a transmission company to develop a framework for quantifying production cost-benefits, capacity and total resource cost-benefits, hedging and risk management benefits, reliability benefits, and competitive benefits. Quantified benefits for different futures and sensitivities and presented analyses in testimony before the state commission.
- **Transmission Investments and Congestion.** Worked with executives and the board of an independent transmission company to develop a metric indicating access and congestion-related benefits provided by transmission investments and operations.
- **Transmission Access Charge Design.** Assisted the California Independent System Operator and a working group of stakeholders to revise the structure of transmission access charges in the context of membership negotiations with non-participating transmission owners. Managed extensive data collection, offered cost-benefit analyses of various access charges and membership scenarios, and presented analyses at monthly stakeholder meetings and at FERC settlement conferences. Drafted ISO implementation guidelines, revised transmission tariff language, and testified on the costs and benefits of new access charge methodology.
- **International Transmission Pricing Review.** On behalf of an energy trading company, prepared a study analyzing the price and non-price terms of transmission access in Germany, and compared transmission pricing and access conditions in two German domestic network industries and four competitive electric power markets in Europe and the U.S. Presented the results to the German economics ministry, the German office of the chancellor, and the industry trade associations involved in the restructuring process.

Strategy and Planning

- **Strategic Planning Effort to Develop an Integrated Services Platform.** Worked with two electric cooperatives and their G&T Cooperative to outlining a strategic plan to develop an integrated services platform that would help coordinate efforts across member cooperatives, their G&T cooperative to support new service offerings to their retail customers.
- **Strategic Planning for Cooperative Generation and Transmission Company.** Co-managed a long-term strategic planning effort with executives and managers of a G&T Cooperative and its distribution company members. Presented materials on technology trends, rate structure challenges and solutions, and challenges with regional transmission cost allocations. Facilitated the development of long-term industry scenarios and strategic responses to develop a comprehensive corporate strategy.
- **Scenario-based Transmission Planning to Address Long-term Uncertainties.** For the Electric Reliability Council of Texas (ERCOT), facilitated ERCOT staff and stakeholder sessions for

developing scenarios of a wide range of plausible futures for use in ERCOT's long-term transmission planning effort.

- **Strategic Planning, Public Power Company.** Co-managed the facilitation of a corporate-wide long-term strategic planning effort for a large, vertically-integrated public power company. Presented introductory materials on long-term industry trends, strategic implications of RTO membership, and opportunities in the regional transmission space. Helped company executives assess the corporation's strengths and weaknesses, risks and major uncertainties, and strategic opportunities. Assisted in the specification of long-term industry scenarios and strategic responses to develop a comprehensive corporate strategy. Consistent with that corporate strategy, facilitated development near and long-term strategic initiatives, business plans, and performance metrics for the company's financial, fossil supply, nuclear, delivery, customer services, and corporate service divisions.
- **Strategic Planning, Investor-Owned Utility.** Co-managed a team assessing strategic opportunities and risks for a Midwestern investor-owned combination utility. Evaluated both industry restructuring and a specific merger proposal; organized and facilitated an off-site retreat with the utility's senior executives to assess the company's market position, identify key industry-related future uncertainties, and understand the interdependence of regulatory and business strategies; and conducted a benchmark analysis to quantify the client's strengths and weaknesses by lines of business relative to immediate competitors and the region as a whole. Simulated the regional generation market to forecast likely competitive market prices and their sensitivity to factors such as nuclear outages and changes in transmission constraints; valued the utility and its potential merger partner on both a scenario- and business-segment-specific basis; and simulated alternative business strategies' impacts on the company's earnings and overall financial performance.
- **Independent Transmission Planning.** Guided a vertically-integrated utility and an independent transmission company through a broad-based transmission planning effort to identify potentially valuable "strategic" transmission projects and quantify and qualitatively discuss the benefits of the identified portfolio of strategic projects.
- **Strategic Assessment of Transmission Investment Opportunities.** Estimated 20-year transmission investment needs, including for public policy-driven projects, by region and evaluated each region's opportunities and challenges for non-incumbent transmission owners.
- **Transmission Industry Strategy.** Helped U.S. and Canadian companies develop business strategies pursue transmission investment opportunities and responses to new FERC regulations, such as competitive opportunities and threats created by the elimination of rights of first refusal.
- **Power Procurement Strategy.** Assisted an Illinois utility in developing procurement strategies for the supply of regulated generation service in a retail access environment and evaluated alternative procurement strategies. Developed best practices through a survey of procurement in other retail access states, retail rate design, analysis of RTO seams and

nascent wholesale markets participation in commission-sponsored roundtable discussion, and preparation of a whitepaper discussing the utility's specific procurement strategy proposal.

- **Strategic Assessment of Competitive Position.** For a Northeastern electric utility, analyzed the utility's competitive position in retail and wholesale markets, quantified the extent of financial exposure, and developed regulatory and business strategies to minimize the potential for stranded investments.
- **Rate Case Strategy.** Assisted a utility's in-house and outside counsel in the management of a $250 million rate complaint by a state regulatory commission's staff. Developed case strategy on economic and policy matters, coordinated key policy witnesses, formulated arguments for rebuttal testimony, and assisted in depositions and cross examination of opposing witnesses. Recommended an alternative regulation plan and settlement proposal, and supported the drafting of motions and other legal documents involving technical subject matters.

Analysis and Mitigation of Market Power

- **Mitigation of Buyer-side Capacity Market Bids.** Reviewed and responded to NYISO analyses and methodology used to implement its buyer-side Mitigation Exemption Test.
- **Market Monitoring and Market Power Mitigation.** For PJM, examined the market power mitigation practices used in U.S. and international organized electricity markets. Reviewed antitrust literature, academic research, and guidelines used to develop an appropriate definition of market power and market power abuse, and evaluated the objective standards that should be applied to monitoring electricity markets and mitigating market power. Assessed the extent to which "best practices" had developed and offered specific recommendations regarding possible changes in PJM's market power mitigation practices.
- **Market Impact Analysis.** For a major independent power producer who self-reported a failure to disclose a plant outage, analyzed the impacts of the undisclosed outage on markets and operations of ISO New England, including the ISO's day-ahead and real-time energy markets, operating reserves markets, forward reserves markets, capacity markets, regulation services, and out-of-merit and reliability-must-run dispatch costs.
- **Eastern U.S. Utility Merger.** Analyzed the market power, market structure, and energy policy implications of a proposed merger that would create by the largest U.S. electric utility and generating company. Filed affidavit that discussed merger-related impacts and critically reviewed applicants' competitive screening analysis.
- **Investigation of Power Crisis.** Co-managed The Brattle Group's investigation and evaluation of the California electric power crisis. Coordinated an extensive discovery effort and the in-depth analysis of market data and other evidence, such as trading records and compliance logs. Supervised the evaluation of numerous trading strategies and the extent to which individual market participants used those strategies to game market rules and manipulate the spot energy and ancillary service markets in California. Provided a detailed analysis of market participants' bidding strategies, the extent of economic and physical withholding by

suppliers, the potential for coordinated interaction and collusion, and the relationship between market fundamentals, market rules, and the behavior of market participants.

- **German Utility Mergers.** On behalf of a power marketer in Europe, presented to the German Cartel Office and the Merger Task Force of the European Community analyses of horizontal and vertical market power implications associated with two mergers involving four major German utility companies. Developed and presented mitigation measures to address the identified concerns.
- **U.S. Utility Merger.** Analyzed vertical market power and mitigation options for testimony in a FERC electric-utility merger proceeding. Performed qualitative and quantitative assessment of applicants' pre- and post-merger abilities and incentives to exercise market power in generation through the manipulation of available transmission capacity and transmission line loading relief (TLR) procedures. Analyzed RTO membership scenarios for their effectiveness in mitigating identified market power concerns.
- **Midwestern U.S. Utility Merger.** In a utility merger case, assessed vertical and horizontal market power concerns raised by the merger proposal; explored the potential for generation-based exercise of vertical market power; and performed an in-depth examination of the UK experience with a fully independent system operator and market power abuses during transmission constraints. Developed mitigation measures, assisted counsel in drafting the motion to intervene and protest, and supported answering and cross rebuttal testimonies for filing with the U.S. Federal Energy Regulatory Commission.
- **British Utility Mergers.** For a power marketer and developer of independent power projects in Great Britain, prepared comments in regard to proposed mergers between major generators and two large regional electricity companies in England and Wales. Filed comments in the Mergers and Monopolies Commission's investigation of the generators' attempt to vertically integrate.
- **Midwestern Utility Merger.** In a contested utility merger case, helped prepare testimony on cost-of-capital impacts and the regulatory risks associated with competing merger offers, and assessed the impacts of merger savings, acquisition premiums, and the financial structure of merger offers on expected benefits to shareholders of both the target and the acquiring companies.
- **Competition in Satellite Services.** Analyzed U.S. international satellite video services and coauthored the expert report that was filed with the FCC. Documented the evolution of effective competition and addressed industry structure, market power, excess capacity, pre-subscription of planned facilities, and competition from the threat of entry.
- **International Telecom Competition.** For a major corporation providing international telecommunications services, analyzed industry structure, market power, and the extent of competition from planned and potential telecommunication facilities. Supervised the quantitative analyses and coauthored the expert report filed with the FCC and distributed to government agencies and communications firms in more than 130 countries.

- **Telecom Merger.** For presentation to the Antitrust Division of the U.S. Department of Justice, analyzed market power implications associated with a proposed merger of major telecommunications carriers, focusing on likely unilateral effects and coordinated interaction, merger-related efficiencies, and the likelihood that entry would mitigate identified concerns. Potential unilateral price increases were predicted through market simulations within a differentiated products framework.
- **Satellite Merger.** For an international telecommunications carrier, analyzed the economic implications of a proposed merger between two of its competitors. The analysis, filed with the Federal Communications Commission, evaluated vertical control relationships among subsidiaries, the significance of merger benefits, and the increased cost of asymmetric regulatory treatment of competitors.

Storage and Generation Asset Valuation

- **Evaluation of Solar+Storage Asset.** For a developer/investor interested in a project that combines solar with storage, evaluated the potential value that the storage adds to the solar project and the potential revenues that the project can gather.
- **Grid-integrated Energy Storage in Texas.** For Oncor, the largest transmission and distribution utility in Texas, assessed the value of 1,000 MW to 8,000 MW of proposed grid-integrated (distribution-level) battery storage deployment in terms of its short- and long-germ energy and ancillary service market benefits, generation investment deferral benefits, avoided and deferred transmission and distribution costs, and reliability value provided to customers. Analyzed both short- and long-term market impacts in light of increasing levels of intermittent renewable energy generation for both typical and challenging weather and load conditions, showing an optimal deployment level of 3,000 to 5,000 MW. The assignment included development of business models suitable for the regulatory requirements in the Texas restructured power market, including different asset ownership structures as well as auctions and joint ventures to separate regulated and competitive uses of the batteries.
- **Behind-the-Meter Storage in California.** Supported an investment fund's due diligence effort for investment in a developer of distributed, behind-the-meter storage devices. Analyzed the overall value proposition, cash flows, business risks, and operating characteristics of two alternative business models involving bilateral contracts with commercial retail customers and the local distribution utility as well as participation in the local wholesale markets for energy, ancillary services, demand response, and local resource adequacy. Also analyzed current market design and proposed design changes by the CAISO and CPUC to facilitate wholesale market participation of behind-the-meter storage devices.
- **Valuation of CHP Alternatives.** For customer group with electricity, steam, and chilled water demands validated analyses of alternative supply options, including building a new CHP plant, contracting with existing provider, or buying an existing plant. Performed sensitivity analysis and valuation of existing plant under alternative procurement strategies.

- **Pumped Storage.** Analyzed the value of a proposed new pumped storage facility in energy, ancillary services, and capacity markets, while considering the expanding role of renewable energy and intermittent generation in the local power market. Quantified the value of facility to developer and market-wide benefits.
- **Customer Benefits of Generation Project.** For a generation developer, analyzed the customer benefits associated with a proposed long-term contract. Assessed costs and value of contract, fuel diversity and risk mitigation benefits, and the facility's market-wide impacts on congestion, energy, and capacity market prices.
- **Valuation of CHP Contract.** For a large customer of combined-heat-and-power facility, valued existing contract for electricity, steam, and chilled water service. Simulated facility operations, estimated facility operating costs and profits, and compared contract costs with the costs of self provision of the various services.
- **Distributed Energy Storage.** Assessed the value of a proposed distributed power storage device in terms of capacity market, energy market, and ancillary service market benefits; transmission and distribution cost savings; and reliability value provided to customers.
- **Plant Valuation and Portfolio Risk Assessment.** For a western U.S. utility client, evaluated power resource alternatives on the basis of long-term cost and portfolio risk. Estimated the market value of the potential acquisition target, evaluated the value of such asset to client, and analyzed the extent to which new power contracts or new generation assets would affect the level and risk of the client's future revenue requirements. Analyzed extent to which fuel and power price risk hedging could be used to further mitigate portfolio risk.
- **Plant Retirement Valuation.** Supported a Midwestern electric utility in analyzing and valuing nuclear power plant retirement and sales alternatives in the context of the plant's severely-degraded steam generator. Quantified the option value of immediate versus delayed steam generator replacement.
- **Plant Modifications.** For a utility in the Northeast, analyzed the economics of converting an oil-fired steam plant to natural gas. Assessed total plant value on oil, the expected incremental value of the planned conversion, the resulting changes in the regional dispatch order, the required level of variable fuel costs needed to ensure sufficient dispatch and gas consumption, and the option value of maintaining dual-fuel capability given future scenarios of seasonal oil and gas price combinations.
- **Utility Bankruptcy.** Assisted a utility close to bankruptcy in its restructuring efforts: advised on rate-redesign, drafted contracts for power and ancillary service purchases, developed open-access transmission and ancillary services tariffs, and negotiated and drafted a lease-buyback and power marketing arrangement. Developed a stand-alone option that involved organizational and financial restructuring, rate concessions to customers, renegotiation of above-market fuel contracts, and sale-leaseback arrangements for a major generation asset.
- **Stranded Costs.** Co-developed the firm's analytical framework for stranded cost evaluation, addressing common errors made in such generation asset valuations.

- **Hostile Takeover Attempt.** For a utility in a hostile take-over attempt, quantified the implications of stranded assets for both the target and acquiring utility. Modeled plant-by-plant revenue requirements, refined a regional generation model to forecast competitive market prices for power, valued potentially stranded regulatory assets, and analyzed total shareholder exposure under various deregulation and cost-recovery scenarios. Showed that the value of the merger offer was significantly reduced by high stranded asset exposure of the acquiring utility.
- **Price Forecasting.** Helped a major utility analyze the regional competitive environment and forecast delivered electricity prices for different customer classes and load shapes under various deregulation scenarios. Estimated the impact of deregulation on the financial performance of the utility.
- **Purchased Power Risks.** For the Edison Electric Institute, studied purchased power risk allocation, the effect on utilities' cost of capital, and the impact of financial leverage on the reliability of non-utility generators. Developed a framework that allows the detection of risk transfers and the quantification of adequate compensation.
- **Company Valuation.** Valued the equity of a startup telecommunications company providing backbone fiber optic infrastructure through electric power transmission lines.

Ratemaking and Incentive Regulation

- **Construction Work in Progress (CWIP).** Submitted testimony and testified in hearing about the desirability of CWIP in ratebase treatment for major transmission investments.
- **Transmission Incentives.** Helped Canadian clients understand and evaluate transmission operations and investment incentives offered by U.S. and U.K. regulatory commissions.
- **Fuel and Environmental Adjustment Clauses.** Undertook a comprehensive survey of rate adjustment clauses for fuel, purchased power, and environmental capital costs. Assisted client in tariff design for fuel and environmental rate riders. Researched efficiency incentive provisions, RTO cost allocations, treatment of off system sales margins, and other design features.
- **Fuel and Purchased Power Incentives.** Performed a comprehensive survey of regulatory incentive mechanisms used with fuel and purchased power adjustment clauses. Helped client design incentive mechanisms for RTO and non-RTO market environment.
- **Major Rate Case.** Supported a large Midwestern utility in filing a $350 million rate increase request. Worked with counsel and executives to develop policy testimony and helped coordinate testimony of 26 witnesses, focusing on surveys of state regulatory practices, cost of capital, test-year normalizations, rate structure, off-system sales, and the design and implementation of a fuel and purchased power adjustment clause. Developed rate comparisons, production cost benchmarking, and various facts and exhibits used in policy testimonies and the company's public relations effort.

- **Retail Rate Structure for Distribution Service.** Worked with an independent generator to analyze and testify about the reasonableness of the local utility's delivery service rate structure offered to station-use customers.
- **Capacity Cost Adjustment Clauses.** Reviewed use of rate adjustment clauses for purchased energy and capacity in states with significant reliance on long-term purchased power contracts. Submitted testimony reporting that the vast majority of such states allow rate adjustments for the capacity portion of purchased power. Explained benefits of rate adjustments, which include mitigation of imputed debt.
- **RTO Blackstart Service Charges.** For a Northeastern RTO, determined costs of providing blackstart service from generating unit to set blackstart ancillary service charges.
- **Weather Normalization.** For a utility in the Southeast, reviewed existing weather normalization process and diagnosed problems with weather data and regression model. Developed alternative daily and monthly normalization models. Improved degree day specification, selection of weather stations, and regression specification to double prediction accuracy and improve stability of normalization process.
- **Implementation of State Regulatory Policies on Fuel and Environmental Cost Recovery.** Supported client's effort to implement rate riders for fuel, purchased power, and environmental compliance costs. Surveyed state regulatory approaches to financing and recovery of utilities' environmental capital projects, variable environmental costs, and purchased power and fuel costs. Documented rate riders and financing mechanisms used to facilitate recovery of such costs in non-restructured states.
- **Code of Conduct.** Assisted a utility in analyzing the operational implications and economic rationale of code of conduct standards, ring fencing requirements, and retail access reciprocity clauses.
- **Depreciation Policy.** Developed arguments for presentation in a remanded regulatory proceeding in support of the standard treatment of net salvage costs for depreciation purposes. Prepared depreciation benchmarking analyses and supported the company's Chief Financial Officer and Controller with the preparation of their testimonies.
- **Complex State Rate Case.** Assisted a utility's in-house and outside counsel in the case management of a $250 million rate complaint by a state regulatory commission's staff. Developed case strategy on economic and policy matters, coordinated key policy witnesses, formulated arguments for rebuttal testimony, and assisted in depositions and cross examination of opposing witnesses. Recommended an alternative regulation plan and settlement proposal, and supported the drafting of motions and other legal documents involving technical subject matters.
- **Incentive Regulation.** On behalf of a Midwest electric utility, prepared a whitepaper assessing the utility's incentive regulation plan and documenting the types and advantages of incentive regulation, the status and development of incentive regulation in the U.S. electric

utility and telecommunications industries, and the attributes and observed benefits of well-designed incentive plans.

- **Rate Unbundling.** On behalf of a combined electric and natural gas utility in the Northeast, analyzed, evaluated, and testified on the proposed regulation of utilities' unbundled customer billing function.
- **Change in Ratemaking Methodology.** For a group of pipeline carriers, analyzed construction, cost recovery, and operational risks and required rates of return of the Trans Alaska Pipeline System; supported testimony on the principles of fair switches in ratemaking methodologies and how significant up-front construction and cost recovery risks needed to be compensated in allowed returns; and assisted counsel in the cross-examination of opposing experts and in drafting economic arguments in legal briefs.
- **Nuclear Plant Performance and Cost Disallowance.** Supported a Northeastern utility in analyzing and responding to intervenors' recommended disallowance of stranded cost recovery based on claims of poor nuclear plant performance. Benchmarked nuclear plant operations.
- **Incentive Regulation.** Participated in the design of a comprehensive incentive mechanism to replace traditional cost-of-service regulation for a Northeastern gas distribution company; designed a price cap for base rates, storage and transportation costs, and a market-index-based mechanism to address the cost of gas supply. Sharing bands were devised to hold financial risks within politically and operationally acceptable levels, and a quality of service incentive was developed to prevent deterioration of reliability and service quality.
- **Regulatory Risks.** Helped prepare a report and executive brief for a New England electric utility, discussing in detail the concepts of asymmetric regulatory risk and appropriate compensation for stranded investment exposure in the face of industry deregulation.
- **Storm Damage.** For a utility in Hawaii, supervised the risk evaluation and cost of capital analyses in a case involving cost recovery associated with a natural disaster that destroyed a large portion of the utility's rate base. Helped prepare direct testimony, drafted rebuttal testimony addressing six opposing witnesses, and assisted counsel in the cross examination of opposing witnesses.
- **Innovative Rates.** For a rate-structure filing of a Northeastern utility, drafted direct and rebuttal testimony on the implications of innovative rate structures for various customer groups, the regional economy, and the competitive position of the utility.
- **Incentive Regulation.** Designed an incentive regulation mechanism covering non-fuel operating and maintenance expenses for a major Northeastern utility; reviewed and evaluated incentive regulation mechanisms for a leading natural gas pipeline company.
- **Demand Side Management.** For the Electric Power Research Institute, reviewed and developed economic analyses for the evaluation of demand side management programs within a research project focused on utility capital budgeting.

- **Fuel Switching.** Developed and evaluated economic arguments for end-use fuel switching and formulated guidelines for the objective allocation of fuel-switching costs and benefits between electric and natural gas utilities.
- **DSM Incentives.** Drafted testimony on cost recovery and incentive mechanisms for demand side management programs, outlining the pros and cons of revenue decoupling versus lost base revenue recovery mechanisms.
- **Manufactured Gas.** For a utility rate filing, researched the prudence of past operations in manufactured gas plants, standard storage and disposal practices, and toxicology and public health issues during the early 1900s.
- **Direct Access.** Prepared a study analyzing the unique risks and benefits of a bill to introduce direct access to an international satellite organization in light of the organization's ongoing privatization efforts. Coauthored a report analyzing the costs and benefits of direct access to international telecommunications satellites in the context of industry restructuring.
- **Cross Subsidization.** For a provider of international mobile telecommunications services, analyzed claims of cross-subsidization between an international consortium and a subsidiary scheduled to develop and launch a new satellite system.
- **Incentive Regulation.** For a client representing a long-distance telecommunications company, assessed the merits of an incentive regulation package filed by a regional bell company.

Contract Disputes and Commercial Damages

- **Long-Term Power Purchase Contracts.** Provided litigation support to U.S. and Canadian clients involved in contract disputes of power purchase agreements signed in the late 1960s and early 1970s. Analyzed industry environment and resource options available at the time, purpose of the agreement in context of resource needs, and impact of industry restructuring on the contracts.
- **Arbitration of O&M Contract Dispute.** On behalf of O&M services provider, submitted expert report analyzing and responding to damage claims associated with disagreement over the operating agreement for a co-generation plant.
- **FTR Trading and Market Manipulation Claims.** For PJM in a district court case, analyzed from a market gaming and market manipulation perspective the FTR trading and virtual bidding activity of hedge fund subsidiaries.
- **Long-Term Contract Dispute.** For the California Attorney General, supported expert testimony on damages and industry practices in a breach of contract claim. Assisted counsel in developing economic facts, arguments, and case theory.
- **Power Contract Dispute.** Analyzed a contract dispute involving agreement to sell capacity, energy, and ancillary services. Testified in an arbitration case on industry practices regarding

implementation and application of the agreement and the validity of claims made by the plaintiff in particular with respect to ancillary services.

- **Commercial Damages.** Analyzed lost sales opportunities in energy and ancillary services markets and quantified associated damages due to a wildfire caused by railroad maintenance work.
- **Class Action Suit.** Assisted counsel in evaluating ability-to-pay matters in the context of a class action suit against tobacco companies. The assignment also involved the identification and support of the expert witness.
- **Litigation Risk Assessment.** With regard to insurance coverage issues and settlement strategies, assessed litigation risks, expected future remedial costs, and remedial cost distributions related to Superfund landfills.
- **Property Damages.** Planned and supervised extensive econometric analyses of property value impacts in the proximity of Superfund landfills to support the testimony of two expert witnesses.
- **Telecom Contract Dispute.** Advised counsel on economic issues and industry pricing practices related to a contract dispute involving a satellite's in-orbit performance. Analyzed the economic impact of impaired satellite performance, plaintiff's damage claims, and regional satellite market conditions. Developed mitigation strategies that substantially reduced damages and provided alternative damage estimates. The case settled in the early stages of arbitration.
- **Contract Termination Damages.** Prepared and submitted expert testimony in a contract termination dispute involving direct-to-home satellite service and damage claims in excess of $100 million; determined damages from lost profits resulting from contract termination and alleged interference with certain business expectancies; assessed proper scope of mitigated damages in the context of efficient contract termination and efficient pre-termination behavior by the contracting parties.
- **Arbitration of Rate Dispute.** Assisted a major U.S. long-distance carrier in arbitration proceedings on wholesale rates for resold local service. Analyzed wholesale discounts for operator/directory assistance services and appropriate discounts in the presence of cross subsidies between interstate and intrastate services.

TESTIMONY AND REGULATORY FILINGS

Before the Arkansas Public Service Commission (Docket No. 17-038-U), the Texas Public Utilities Commission (Docket No. 47461), the Louisiana Public Service Commission (Docket No. U-34619), the Corporation Commission of Oklahoma (Cause No. PUD 201700267), and the Federal Energy Regulatory Commission (Docket No. EC18-40), *Direct and Rebuttal Testimonies of Johannes P. Pfeifenberger in the Matter of the Windcatcher Energy Connection Project on behalf of Southwestern Public Service Company and Oklahoma* , June 2017 through January 2018.

Before the Federal Energy Regulatory Commission, Docket No. AD16-18-000, *Comments of Mr. Johannes P. Pfeifenberger and Ms. Judy Chang Regarding Competitive Transmission Development Technical Conference*, October 3, 2016.

Before the Cour Supérieure, Province de Québec, District de Montréal, Canada, Case No. 500-17-078217-133, *Expert Report and Oral Testimony of Johannes Pfeifenberger: CF(L)Co's Sales of "Interruptible" Power*, in Hydro Québec vs. Churchill Falls (Labrador) Corporation Limited, April 17 and December 2015.

Before the National Energy Board, Canada, Filing A70152, "Market Assessment Report", Annex 2 to ITC Lake Erie Connector LLC (ITC or ITC Lake Erie) Application for an Election Certificate for the Lake Erie Connector Project, May 22, 2015.

Before the Missouri Public Service Commission, File No. EA-2014-0207, "Wind Integration Analysis for the Grain Belt Express HVDC Line," report on behalf of Clean Line Energy Partners, April 13, 2015.

Before the Federal Energy Regulatory Commission, Docket No. ER14-2940-000, re *PJM Interconnection, LLC*, Affidavit of Johannes P. Pfeifenberger and Bin Zhou, November 5, 2014. Attachment B to Answer of PJM Interconnection, L.L.C. to Protests and Comments, November 6, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER15-117-100, EL14-99-000 (Not consolidated), re *ISO New England Inc.*, Affidavit of Johannes P. Pfeifenberger, November 5, 2014, Attachment A to Brookfield Energy Marketing LP's Protest and Motion to Intervene, November 6, 2014.

Before the Federal Energy Regulatory Commission, Docket Nos. ER14-33 and ER14-1332, re *DATC Path 15*, Prepared Direct Testimony of Johannes P. Pfeifenberger on behalf of DATC Path 15 LLC, February 18, 2014.

Before the State of Maine Public Utilities Commission, Docket No. 2012-00589 re: *Maine Public Utilities Commission Investigation into Reliability of Electric Service in Northern Maine*, Testimony and Exhibits of Judy Chang and Johannes Pfeifenberger on behalf of Maine GenLead, LLC August 2, 2013; and Supplemental Testimony of Judy Chang and Johannes Pfeifenberger, January 17, 2014.

Before the Federal Energy Regulatory Commission (Docket Nos. EC12-145-000 and EL12-107-000, Exhibit No. ITC-600), the Louisiana Public Service Commission (Docket No. U-32538), the Council of the City of New Orleans (Docket No. UD-12-01), the Arkansas Public Service Commission (Docket No. 12-069-U), the Mississippi Public Service Commission (2012-UA-358), and the Public Utilities Commission of Texas (Docket No. 41223), Direct, Rebuttal, and Sur-Rebuttal (CNA and Arkansas) Testimonies of Johannes Pfeifenberger on behalf of ITC Holdings re: ITC's acquisition of the Entergy Transmission System, September 2012–August 2013.

Before the Federal Energy Regulatory Commission, Docket No. EL12-98, Affidavit of Johannes Pfeifenberger on behalf of Hudson Transmission Partners, LLC re: NYISO capacity market offer mitigation, filed August 3, 2012.

Before the Federal Energy Regulatory Commission, Docket No. EL11-50, Affidavit and Reply Affidavit of Johannes Pfeifenberger on behalf of NRG Energy re: NYISO capacity market offer mitigation, filed September 23 and October 25, 2011.

Before the Federal Energy Regulatory Commission, Docket Nos. ER11-4069 and ER11-4070, Direct Testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies re: the Public Policy, Congestion Relief, and Economic Benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the Alberta Utilities Commission, Application 1606895, Proceeding ID 1021, Rebuttal Testimony on behalf of AltaLink Management Ltd re: Treatment of Construction Work in Progress, filed April 26, 2011.

Before the Federal Energy Regulatory Commission, Docket No. RM10-10-000, Filed Comments re: Notice of Proposed Rulemaking on Planning Resource Adequacy Assessment Reliability Standard, December 27, 2010 (with K. Carden and N. Wintermantel).

Before the Federal Energy Regulatory Commission, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the Public Policy, Reliability, Congestion Relief, and Economic Benefits of the Atlantic Wind Connection Project, filed December 20, 2010.

Before the Maryland Public Service Commission, Administrative Docket PC22, Filed Comments In the Matter of the Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results, October 1, 2010 (with K. Spees).

Before the Federal Energy Regulatory Commission, Docket No. RM10-23-000, Filed Comments re: Notice of Proposed Rulemaking on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, September 29, 2010 (with P. Fox-Penner and D. Hou).

American Arbitration Association, AAA No. 13-198-02918-08, General Electric International, Inc. vs. Project Orange Associates, LLC; Expert Report and Oral Testimony on behalf of General Electric International re: Operating Agreement Dispute, October 12, 2009 and January 5, 2010.

In the United States District Court for the Eastern District of Pennsylvania, Case No. 08-cv-3649-NS, Expert Report on behalf of PJM Interconnection LLC re: hedge fund trading activities of financial transmission rights, February 22, 2010.

Before the Federal Energy Regulatory Commission, Docket No. AD09-8-000, Filed Comments re: regional transmission planning and cost allocation, December 18, 2009 (with P. Fox-Penner and D. Hou).

Before the Missouri Public Utilities Commission, Case No. ER-2010-0036, Direct Testimony on Interim Rates on Behalf of AmerenUE, October 20, 2009.

Before the Maine Public Utilities Commission, Docket No. 2008-156, *Assessment of a Maine ISA Structure as a Possible Alternative to ISO-NE Participation*, Report and Oral Testimony on behalf of Central Maine Power Company and the Industrial Energy Consumer Group, May 2009.

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, Direct Testimony on behalf of American Transmission Company re: transmission cost-benefit analysis, January 17, 2008.

Before the Missouri Public Utilities Commission, Case No. EO-2008-0046, Rebuttal, Supplemental Rebuttal, and Surrebuttal Testimony on behalf of Midwest Independent Transmission System Operator, Inc. re: Aquila RTO cost-benefit analyses, November 30, 2007, December 28, 2007 and February 27, 2008.

Before the Maine Public Utilities Commission, Docket No. 2007-317, *An Assessment of Retail Rate Trends and Generation Costs in Maine*, Whitepaper filed on behalf of Independent Energy Producers of Maine, September 5, 2007 (with A. Schumacher).

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, *Planning Analysis of the Paddock-Rockdale Project*, report by American Transmission Company re: transmission cost-benefit analysis, April 5, 2007 (with S. Newell and others).

Before the Alberta Energy and Utilities Board, Proceeding No. 1468565, submission on behalf of AltaLink Management Ltd. re: Benchmarking the Costs and Performance of Utilities using a Uniform System of Accounts, October 2006 (with C. Lapuerta).

Before the Arizona Power Plant and Transmission Line Siting Committee, Docket No. L-00000A-06-0295-00130, Case No. 130, Oral Testimony on behalf of Southern California Edison Company re: economic impacts of the proposed Devers-Palo Verde No. 2 transmission line, September and October, 2006.

Before the Federal Energy Regulatory Commission, Docket No. EL-06097-000, Affidavit and Rebuttal Affidavit on behalf of WPS Resources Corporation re: benefits of implementing a joint and common market across the MISO-PJM service areas, August 15 and October 2, 2006.

Before the Maine Public Utilities Commission, Docket No. 2005-554, Direct Testimony and Surrebuttal on behalf of Penobscot Energy Recovery Company re: retail rate structure for station-use distribution service, June 7 and September 29, 2006.

Before the Colorado Public Utilities Commission, Docket No. 06S-234EG, Direct Testimony on behalf of Public Service Company of Colorado re: purchased power rate adjustment mechanisms and imputed debt of purchased power, April 14, 2006.

In the Matter of Binding Arbitration Between La Paloma Generating Trust, Ltd, as Revocably Assigned to La Paloma Generating Company, LLC, v. Southern California Edison Company, JAMS CASE NO.

1220032122, Direct and Rebuttal Testimony on behalf of Southern California Edison re: Power Contract Dispute, June and July 2005.

Before the Federal Energy Regulatory Commission, Docket No. EC05-43-000, Affidavit and Supplemental Affidavit on behalf of Ameren Services Company re: *Exelon Corporation and Public Service Enterprise Group Incorporated, Joint Application for Approval of Merger*, April 11 and May 27, 2005 (with P. Fox-Penner).

Before the Illinois Commerce Commission, Docket Nos. 05-160, *et al.*, Direct Testimony on Behalf of Central Illinois Light Company, Central Illinois Public Service Company, and Illinois Power Company re: Competitive Procurement of Retail Supply Obligations, February 28, 2005.

Before the Federal Energy Regulatory Commission, Docket Nos. ER04-718-000 *et al.*, Prepared Supplemental Testimony on Behalf of the Michigan Utilities re: Financial Impact of ComEd's and AEP's RTO Choices, December 21, 2004 (with S. Newell).

Before the Federal Energy Regulatory Commission, Docket Nos. ER04-375-002 *et al.*, Declaration re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, August 13, 2004; Prepared Direct and Answering Testimony on Behalf of the Michigan-Wisconsin Utilities, September 15, 2004 (with S. Newell).

Before the Federal Energy Regulatory Commission, Docket No. ER00-2019-0000, *California Independent System Operator Corporation*, Direct Testimony and Rebuttal Testimony on Behalf of the California Independent System Operator re: Redesign of Transmission Access Charges, February 14, 2003 and October 2, 2003.

Before the Federal Energy Regulatory Commission, Docket No. ES02-53-000, *Midwest Independent Transmission System Operator, Inc.*, Prepared Direct Testimony on Behalf of the Midwest Independent Transmission System Operator re: Rate Design for ISO Administrative Cost Recovery, September 24, 2002.

Before the Federal Energy Regulatory Commission, Docket No. RT01-87-001, *Midwest Independent Transmission System Operator, Inc.*, Affidavit on Behalf of the Midwest Independent Transmission System Operator re: Inter-RTO Coordination, August 31, 2001 (with P. Fox-Penner).

Before the Public Service Commission of the State of Missouri, Case No. EM-96-149, *White Paper on Incentive Regulation: Assessing Union Electric's Experimental Alternative Regulation Plan*, on behalf of Ameren Services Company, February 1, 2001 (with D. Sappington, P. Hanser, and G. Basheda).

Before the Federal Energy Regulatory Commission, Docket No. ER00-2019-0000, *California Independent System Operator Corporation*, Testimony before Settlement Judge on behalf of the California ISO re: Redesign of Transmission Access Charges, July 12 and August 10, 2000.

Before the State of New York Public Service Commission, *In the Matter of Customer Billing Arrangements*, Case 99-M-0631, Affidavit on behalf of New York State Electric and Gas Corporation, April 19, 2000 (with F. Graves).

Before the Federal Communications Commission, "An Economic Assessment of the Risks and Benefits of Direct Access to INTELSAT in the United States," Report filed *In the Matter of Direct Access to the INTELSAT System*, IB Docket No. 98-192, File No. 60-SAT-ISP-97, December 21, 1998 (with H. Houthakker and J. Green).

Before the Federal Communications Commission, "A Response to the Economists Inc. Study: Preliminary Competition Analysis of Proposed Lockheed Martin/COMSAT Transaction," December 1998 (with C. Lapuerta).

Before the United States District Court, Central District of California, Expert Report of *The Brattle Group* re: Contract Termination Damages; *Comsat Corporation v. The News Corporation, Limited, et al.*, July 1, 1998.

Before the Federal Communications Commission, "Response to Comments on Comsat's Reclassification Petition," File No. 60-SAT-ISP-97, July 7, 1997 (with H. Houthakker and W. Tye).

Before the Federal Communications Commission, "The Economic Basis for Reclassification of Comsat as a Non-Dominant Carrier," Report filed *In the Matter of Comsat Corporation Petition for Forbearance from Dominant Carrier Regulation and for Reclassification As a Non-Dominant Carrier*, April 24, 1997 (with H. Houthakker and W. Tye).

Before the Federal Communications Commission, "Competition in Transoceanic Switched Voice and Private Line Services to and from the U.S.: 1997 Update," Report filed *In the Matter of Comsat Corporation Petition for Forbearance from Dominant Carrier Regulation and for Reclassification As a Non-Dominant Carrier*, April 23, 1997 (with H. Houthakker and W. Tye).

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“Evaluation of Demand-Side Management Programs” (with others), *Capital Budgeting Notebook*, Electric Power Research Institute, Chapter 12, 1994.

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“Incentive Regulation: Dos and Don’ts” (with W. Tye), Electric Utility Consultants: Strategic Utility Planning Conference, June 1993.

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“Charge It—Financing DSM Programs” (with D. Weinstein), *Public Utilities Fortnightly*, May 1, 1993.

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“The Costs of Hydropower: Evidence on Learning-by-Doing, Economies of Scale, and Resource Constraints in Austria” (with F. Wirl), *International Journal of Energy Research*, Vol. 14, pp. 893-899, 1990.

“Eine ökonomische Analyse alternativer Kraftwerkstypen” (an economic analysis of power supply alternatives) (with F. Wirl), *Girozentrale Quartalshefte*, pp. 21-30, January 1990.

“Eine einfache Charakterisierung der saisonalen Elektrizitätsnachfrage” (a simple characterization of seasonal electricity demand), *Österreichische Zeitschrift für Elektrizitätswirtschaft*, March 1990.

Kraftwerksausbauplanung mit Linearen Optimierungsmodellen am Beispiel Österreichs (power systems expansion planning for Austria with mixed-integer and linear-programming models), Master’s Thesis, Institute of Energy Economics, University of Technology, Vienna, May 1989.

October 10, 2018

Bin Zhou
Principal

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Dr. Bin Zhou is a member of The Brattle Group's Tax and Restructuring Practice. He has twenty years of consulting experience in consumer goods, energy, financial institutions, pharmaceutical and medical devices, 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 (Coca-Cola, Guidant, Eaton, AstraZeneca, and GlaxoSmithKline), bankruptcy (Caesars, U.S. Steel Canada, Nortel, and Ambac), and securities litigations (Parmalat, Enron, etc.). 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, and damages. His most recent experience also includes cost / benefit analyses of legislative policies on the re-insurance industry, and regulatory approval of large-scale infrastructure projects.

In addition, Dr. Zhou is a valuation specialist with extensive experience in complex valuation assignments involving unique risk characteristics, varying operational and financial leverage, and special tax treatment to the investment/financing cash flows. He applied and developed innovative techniques to valuation of utilities, financial institutions, pharmaceutical companies, and special corporate forms (government agencies, employee stock ownership plans, master limited partnerships, and other pass-through entities).

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

- Transfer Pricing and Other Tax Controversies
- Bankruptcy Litigation
- Securities Litigation
- Risk Analysis and Valuation
- Contract Disputes and Damages

EXPERIENCE

Transfer Pricing and Other Tax Controversies

- In Coca-Cola's transfer pricing dispute with the IRS, Dr. Zhou leads 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 the arm's length prices for the transfer of the company's product and marketing intangibles. The trial started in March 2018.
- 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. Brattle's analysis included how the industry dynamics for Class III FDA devices created barriers to entry, and assessing the overall value chain to appropriately price the R&D, manufacturing, and sales functions. 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 about advance pricing agreement cancellations and de novo arm's-length pricing analyses, 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. Eaton won on the liability issue, and Dr. Zhou played an instrumental role in supporting the academic expert testifying 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 Xel 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.

Bankruptcy Litigation

- 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 proceedings, 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

- 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.

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 recent 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 is currently assisting 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

- On behalf of a mutual fund family, Dr. Zhou estimated the economic cost of SEC's proposed regulations of the money market fund industry (floating NAV, capital requirement, and redemption holdback).
- 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 three expert reports and testified at trial in an estate dispute involving annuity valuation, 2014

Submitted an affidavit, joint with Johannes P. Pfeifenberger, in a Federal Energy Regulatory Commission proceeding on merchant generation cost of capital, 2014

Publications and Presentations

"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.

Exhibit No. 2

August 21 Supplement

THE Brattle GROUP

MEMORANDUM

TO: PJM

FROM: Johannes Pfeifenberger and Bin Zhou, The Brattle Group

SUBJ: ATWACC Update for PJM CONE Analysis

DATE: August 21, 2018

One of the inputs to Brattle's analysis of PJM's Cost of New Entry (CONE), for an online date of June 1, 2022, is the after-tax weighted average cost of capital (ATWACC). It is used as the discount rate to annualize new entry investment costs.[1] Following the same analytical approach that has been used since 2011 for PJM's CONE analysis and endorsed by FERC,[2] we conducted an ATWACC analysis (undertaken between December 2017 and January 2018) and recommended an ATWACC of 7.5%. This recommendation incorporated the impact of the reduction in the U.S. federal corporate income tax rate from 35% to 21%.[3]

Financial forecasts for future periods are inevitably limited to the information available at the time of forecasts and expert judgement about future trends. Our original ATWACC analysis had allowed for a higher risk-free rate in our cost of equity analysis by looking at long-term forecast

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1 Note that this cost of capital estimate is used only to determine the annualized value of CONE, not the financial return that investors will actually earn on their investment in the PJM wholesale electricity markets. That actual return will be determined by the capacity market clearing price, which depends on the actual offers that suppliers make into the capacity market auction, in conjunction with margins earned in the E&AS markets. Suppliers will offer into the capacity market based on their actual costs, which can include financing costs that are higher or lower than our estimated cost of capital. If a supplier's bid is competitive, the market will clear at a price equal to or higher than that bid, and the supplier's investors will earn the return that is associated with that market price.

2 FERC Order Conditionally Accepting Tariff Revisions Subject to Compliance Filing, issued on November 28, 2014, 149 FERC ¶ 61,183.

3 Together with the state income taxes, the combined income tax rate is 27.7% (8.5% + 21% × (1 - 8.5%) = 27.715%). Brattle's April 2018 CONE Report incorrectly assumed that, under the new tax law, state income taxes are not deductible for federal income tax purposes at the corporate level.

as a sensitivity analysis. However, as shown by Energyzt[4], the risk-free rate and cost of debt of below-investment grades have increased further since we undertook our ATWACC analysis.

Taking into account the larger-than-expected recent changes in interest rates as well as additional market evidence on U.S. merchant generation business (i.e., the Dynegy acquisition by Vistra), we increase our recommended ATWACC from 7.5% to 8.0%. Our recommended financing components, reflecting this 8.0% ATWACC, are: debt ratio 55%, equity ratio 45%, cost of debt 5.5%, and cost of equity 13.0%:

- We updated the debt and equity ratios from 65%/35% to 55%/45% in response to financial analyst assumptions presented in the Energyzt August 2, 2018 presentation.[5]
- Our initial analysis recommended a 6.5% cost of debt based on a combination of B-rated and BB-rated debt, consistent with the higher 65% debt ratio. At the lower 55% debt ratio, the debt will be less risky and cost of debt will be lower.[6] We believe that the lower 55% debt ratio makes BB the more likely rating associated with the lower leverage.
- The yield of BB-rated bonds has increased to 5.1% (by about 100 basis points) since we undertook our original ATWACC analysis. We therefore lowered our cost of debt recommendation from 6.5% to 5.5%. This 5.5% cost of debt reflects the higher interest rates environment, the reduced risk of debt at the lower debt ratio, and allows for an additional 40 basis points future increase in the bond yield.
- Consistent with the above recommended capital structure ratios, cost of debt, and an 8.0% ATWACC, the cost of equity is estimated to be 13.0%: $13.0\% \times 45\% + 5.5\% \times 55\% \times (1 - 27.7\%) = 8.0\%$.

The rest of this memo explains our additional analysis and rationale for the updates, and responds to some of the points raised by Energyzt.

Figure 1 (update of Figure 6 in the report) presents our 2018 update of the ATWACC (on the very right) and implied ATWACC premiums above the risk-free rate together with our recommendations from previous CONE studies, including the original 2017-based recommendation in our current CONE analysis (the 2011, 2014 and 2017 data are from the original Figure 6). Corresponding to our updated 2018 ATWACC recommendation, the "risk premium" of the ATWACC recommendation over the risk-free rate (20-year Treasury bond

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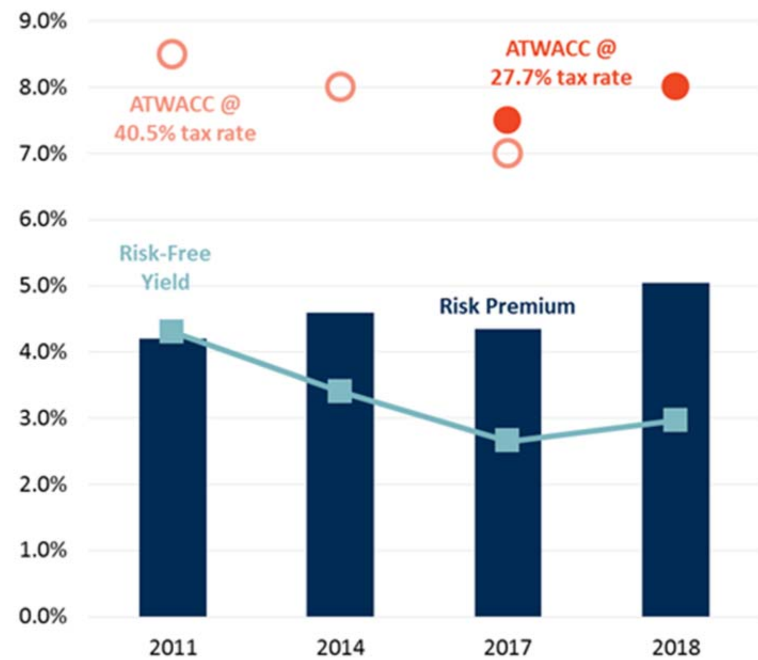
4 Energyzt, PJM Quadrennial Review: Discount Rate, July 27, 2018, available at: https://pjm.com/-/media/committees-groups/committees/mic/20180727-special/20180727-item-02-quadrennial-review-p3-presentation.ashx.

5 Confidential survey results presented by Energyzt to PJM.

6 However, as acknowledged by Energyzt, the change in capital structure will not affect ATWACC.

rates) is now about 5.0%, which is higher than the approximately 4.5% risk premiums of the ATWACCs used in our prior recommendations.[7]

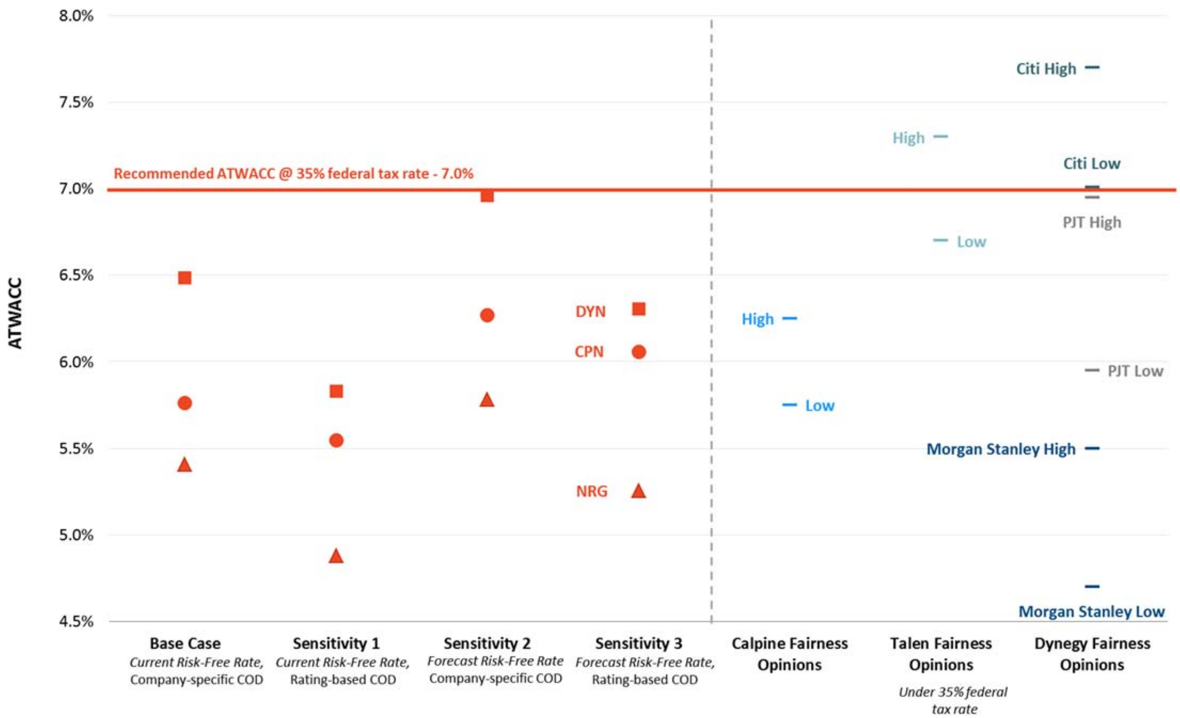
Figure 1. Comparison of Brattle ATWACC Recommendations (2018 Column Represents the Current Update)



When we compare the ATWACC premiums over time, we are implicitly assessing the reasonableness of our recommendation from a historical perspective. We should note that this historical comparison is not the basis or the starting point of our analysis; rather, this comparison against prior recommendations is a benchmarking check of the results from our analysis of market conditions and business risks. Our ATWACC analysis in Figure 2 (based on Figure 7 in the report) incorporates additional market evidence regarding ATWACC from U.S. merchant generation transactions mentioned above, as of November 2017—confirming the original 7.0% ATWACC estimate for the prior 35% corporate tax rate.

7 Note that the risk premium shown in Figure 1 is defined as ATWACC minus the risk-free rate. This is different from the 6.9% market risk premium ("MRP") that is used in the capital asset pricing model (CAPM) to calculate cost of equity: CoE = risk-free rate + beta × MRP. MRP measures the excess return on a stock market portfolio such as NYSE stock index or S&P 500 over the risk-free rate.

Figure 2. ATWACC of U.S. IPPs and Discount Rates from Fairness Opinions as of Nov 2017 (35% Federal Tax Rate)



The starting point of our ATWACC analysis is the quantification of business risks in the U.S. merchant generation business from the market evidence. In our original analysis, consistent with our analyses in previous PJM CONE reports, we examined (1) a sample of U.S. independent power producers (IPPs); and (2) ATWACC-based discount rates used by financial analysts in evaluating recent merchant generation M&A transactions. We also considered a sample of Canadian IPPs in our current PJM CONE report, since two of the U.S. IPPs were acquired. In recognition of higher merchant generation risks compared to the average risk of (partly contracted) IPP portfolios, we recommended an ATWACC at the very high end of the ranges associated with these merchant generation company reference points. In January 2018, this yielded an ATWACC of 7.0% under the 35% federal corporate income tax rate (consistent with Figure 2 above) and 7.5% as a result of the lower tax rates.

In this updated analysis, we added the discount rates used in the fairness opinions of Dynegy's acquisition by Vistra. The Dynegy transaction was announced on October 29, 2017, and the fairness opinions from the financial advisors (Citi for Vistra, Morgan Stanley and PJT for Dynegy) were made public in February 2018, after the conclusion of our initial ATWACC analysis. Each of the three financial advisors involved in that transaction used a distinct range of (ATWACC-based) 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. 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. These estimates, as of October 29, 2017, likely do not yet reflect the impact of the new tax law. Even when including these new data, we believe the original 7.0% applicable under the 35% tax law as shown in Figure 2 is still the most reasonable estimate, as of November 2017. (Our view of ATWACC recommendations obtained from potential lenders as presented to PJM by Energyzt is discussed below.)

There are two necessary adjustments to the 7.0% ATWACC estimate in Figure 2. First, we increased the ATWACC from 7.0% to 7.5% to incorporate the changes in the new tax law. This adjustment was already included in our original recommendation. Second, we now also incorporate new data showing that the risk-free rate and cost of debt have increased since our original work:

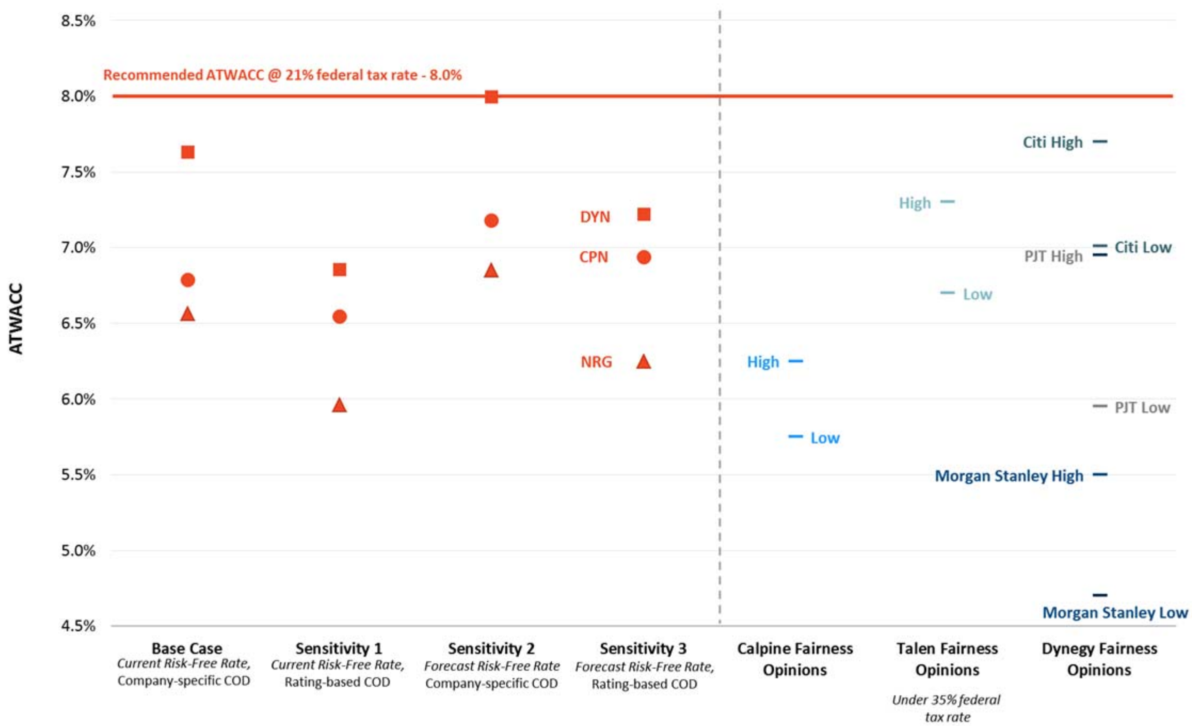
(a) Risk-free Rate: In our analysis we used both a current risk-free rate as measured by the 20-year Treasury bond rate and a forecasted risk-free rate as approximated by the consensus forecasts from BlueChip. The 20-year T-Bond rate increased about 0.3 percent (from 2.65% to 2.96%) since our original analysis. However, the long-term forecast remains at 3.5%;[8]

(b) Cost of Debt: In our analysis we used both rating-based index interest rates (the BB- and B-rate bond yields) as well as company-specific bond yields. The ratings-based bond yield increased by approximately 100 basis points since our original analysis. As for the company-specific yields, because two of the U.S. IPPs are now part of larger corporate parents, their current costs of debt have decreased and will no longer reflect the higher costs of debt for U.S. IPPs. We ignore this decrease and, instead, assume that the IPPs' company-specific borrowing costs (consistent with the sample-companies' debt ratings) have increased by 100 basis points since our initial analysis.

The resulting updated ATWACC estimates for the U.S. IPPs, including the discount rates disclosed in the most recent fairness opinions (which do not reflect the lower federal corporate income tax rate), are shown in Figure 3. Our Base Case and three Sensitivity Cases reflect different combinations of risk-free rates (current v. forecast) and costs of debt (ratings-based v. company-specific) as described in the full report. Based on these updated reference points, we recommend 8.0% as our updated ATWACC.

8 As of March 2018, BlueChip's forecast for a 10 year Treasury Bond for 2020 remains at 3.5%. The five year average for 2020-2024 is 3.7%.

Figure 3. ATWACC under Current Interest Rates (21% Federal Corporate Income Tax Rate)



Beyond the higher interest rates incorporated in the updated ATWACC recommendation, we also respond to four other points that Energyzt raised in regard to our original ATWACC recommendation.

1. Implied Un-Levered Beta

Energyzt bases its 9.7% or higher ATWACC primarily on a historical comparison with the PJM 2014 decision of an 8.0% ATWACC.[9] There are several problems with this analysis.

First, the fundamental premise of this approach is that the implied un-levered beta and risk in PJM, estimated in 2014, should be the same as that estimated in 2018. This premise is not supportable, given evidence presented in our original report showing that ATWACC estimates for U.S. IPPs and discount rates used in merchant generation transactions were lower in 2018 than in 2014.[10] For example, discount rates used in the Calpine fairness opinion (as of August 17,

9 We have not investigated the reference to ISO-NE 2017, but we want to note that the mechanics for estimating ATWACC is different from our approach.

10 PJM CONE Study 2014, Table 25.

2017), ranged from 5.75% to 6.25%. The discount rates for the NRG-GenOn merger in 2012 ranged from 7.7 to 9.2% for NRG and from 9.2–10.2% for GenOn.

Second, if one were to conduct a historical benchmarking analysis, a more straightforward way is to compute the ATWACC premium over the risk-free rate (as we have done in Figure 1 above). At Energyzt's recommended ATWACC of 9.7%, the resulting ATWACC premium above the risk free rate would be 6.7%, well above the premium that existed in the 2014 recommendation.

Third, Energyzt's comparison of the un-levered betas between our 2014 and 2018 recommendations is based on an incorrect application of the un-levering formula:

Un-Levered Beta = Levered Beta / (1 + (1 – Tax Rate) × Debt / Equity).

This formula is based on the corporate finance theory that financial leverage does not affect the asset risk of a company or project,[11] and is used to estimate un-levered betas from levered betas and the observed capital structure.[12] Columns [1] and [4] of Table 1 replicate Energyzt's results: Energyzt pointed to the drop in their calculated un-levered betas from 0.85 to 0.58 as evidence that our current analysis under-estimates risk and ATWACC.[13] However, Energyzt's conclusion is based on an erroneous use of the un-levering formula, which is derived under a constant tax rate, in situations when tax rates change. To see this error, compare columns [3] and [4], where all the cost of capital components are the same, but the tax rates are different: (1) under the higher old tax rate (column [3]), a 7.0% ATWACC corresponds to an un-levered beta of 0.64; whereas (2) under the lower new tax rate, the ATWACC is 7.5% and corresponds to an un-levered beta of 0.58 (as shown in column [4]). Put differently, under Energyzt's method, a lower ATWACC, due entirely to a higher tax rate, would imply higher un-levered business risk! This unreasonable result is artificial solely because the un-levered beta formula is misused. Consequently, any inferences drawing from this comparison of un-levered betas are incorrect.

11 The theory-based un-levered beta formula does not lead to exactly constant ATWACCs. The concept behind the un-levered formula however, is consistent with our empirics-based ATWACC approach.

12 Reversely, a re-levering formula, Levered Beta = Un-Levered Beta × (1 + (1 – Tax Rate) × Debt / Equity), can be used to re-lever un-levered betas to any hypothetical capital structure.

13 Energyzt July 27 presentation, at p. 7.

Table 1. ATWACC, Equity Betas, and Un-Levered Betas

	2014		2018	
	40.50%	29.50%	40.50%	29.50%
	[1]	[2]	[3]	[4]
Assumptions:				
Risk-free Rate	3.40%	3.40%	3.50%	3.50%
Market Risk Premium	6.50%	6.50%	6.90%	6.90%
CoE	13.80%	13.80%	12.80%	12.80%
CoD	7%	7%	6.50%	6.50%
E/V	40%	40%	35%	35%
D/V	60%	60%	65%	65%
Tax Rate	40.50%	29.50%	40.50%	29.50%
ATWACC	8.0%	8.5%	7.0%	7.5%
Implied Betas:				
Levered Beta	1.60	1.60	1.35	1.35
Un-Levered Beta	0.85	0.78	0.64	0.58

Notes:

Levered Beta = (CoE – Risk-Free Rate) / Market Risk Premium;

Un-Levered Beta = Levered Beta / (1 + (1 – Tax Rate) × D/V / E/V).

2. ATWACC Estimates from Lenders

Energyzt presents ATWACC recommendations from several lenders as of November 2017.[14] They range from 7.5% to 12% based on the 35% federal income tax rate. Through our prior experience with interviewing developers and lenders in analyzing the financing cost of merchant generation companies, we believe relying on such a survey would introduce subjective and upwardly-biased results, because (1) developers and lenders tend to, consciously or not, provide cost of capital estimates consistent with the high returns they would like to earn rather than a competitive level of financing costs; (2) these survey results are not binding, and it is not clear that any actual bids or investments have been made with the expectation to earn these rates; and (3) it is unclear whether projects bid into PJM's capacity market at some of the high recommended financing cost assumptions would be sufficiently competitive to clear in the auction.

To avoid the resulting potential upward bias of lender surveys, we prefer to rely on market data for publicly-traded sample companies (with appropriate adjustment for, and consideration of, differences in business risk for PJM merchant generation investments), supplemented by the benchmark ATWACC-based discount rates employed by investment analysts preparing fairness

[14] Energyzt August 2, 2018 confidential presentation to PJM, at pp. 16 – 19.

opinions for merchant generation companies as an additional reference point. The selected fairness opinions have been used by investors in both the target companies and acquiring companies to value actual merchant generation merger and acquisition transactions for which there are corroborative market prices. Hence, the data from fairness opinions have the advantage of being an unbiased reference point. Compared to the potential bias introduced through lender surveys, we believe our approach yields an unbiased and market-based estimate of the cost of capital for merchant generation investments in PJM.

3. Reliance on TransAlta

Energyzt mischaracterized our reliance on Transalta. The company is included in our Canadian IPP sample. Our main conclusion is based primarily on evidence from the U.S. reference points presented in Figures 6 and 7 of our April 2018 report. The fact that our ATWACC recommendation is closer to Transalta's ATWACC is just a coincidence.

4. Comparison to Utility Costs of Equity

Energyzt suggested that our originally proposed 12.8% cost of equity is consistent with their estimated cost of equity for regulated utilities at 65% debt ratio,[15] and therefore must underestimate the cost of equity for merchant generation. However, Energyzt's attempt to re-lever allowed cost of equity from a different book-value capital structure to our recommended capital structure is based on stale costs of equity data: the regulatory costs of equity used in their regression analysis are not all of 2017 or 2018 vintages. Our recommended overall rate of return for merchant generation companies in PJM is well above that of regulated utilities.

15 Energyzt July 27, 2018 presentation, at p. 33.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Docket No. ER19-___-000**

VERIFICATION

Johannes P. Pfeifenberger, being first duly sworn, deposes and states that he is the Johannes P. Pfeifenberger referred to in the foregoing document entitled "Affidavit of Johannes P. Pfeifenberger and Bin Zhou on Behalf of PJM Interconnection, L.L.C.," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

Subscribed and sworn to before me, the undersigned notary public, this 11th day of October 2018.

Debra A. Paolo

Notary Public

My Commission expires: Sep. 4, 2020

{W0173060.1 }

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Docket No. ER19-___-000**

VERIFICATION

Bin Zhou, being first duly sworn, deposes and states that he is the Bin Zhou referred to in the foregoing document entitled "Affidavit of Johannes P. Pfeifenberger and Bin Zhou on Behalf of PJM Interconnection, L.L.C.," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

Subscribed and sworn to before me, the undersigned notary public, this 11 day of October 2018.

Notary Public

My Commission expires: February 15, 2024

ERICA L. DEARY
COMMISSION EXPIRES FEB. 15, 2024
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS

{W0173061.1 }

Attachment G

Affidavit of
Samuel A. Newell and
David Luke Oates

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER19-_____-000**
	)	

AFFIDAVIT OF SAMUEL A. NEWELL AND DAVID LUKE OATES
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. Samuel A. Newell and Dr. David Luke Oates. We are employed by The Brattle Group, as Principal and Associate, respectively. We submit this affidavit on behalf of PJM Interconnection, L.L.C. ("PJM") to describe the analysis we conducted on the performance of PJM's Variable Resource Requirement curve ("VRR Curve") for procuring capacity in its Reliability Pricing Model ("RPM") capacity market. We conducted this analysis as part of PJM's tariff-mandated quadrennial review of the VRR Curve and its parameters, the results of which have informed PJM's proposed revisions to the VRR Curve in the present filing. The entirety of our review is contained in the attached report, *Fourth Review of PJM's Variable Resource Requirement Curve* ("2018 VRR Curve Report"). A copy of that report, which was prepared by us or under our supervision and direction, is set forth in Exhibit No. 2 to this affidavit.

2. Our qualifications as experts derive from our extensive experience evaluating capacity markets and alternative market designs for resource adequacy. Our practice in capacity market design with regional transmission organizations ("RTOs") across North America and internationally has given us a broad perspective on the practical implications of nuanced market design rules under a range of different economic and policy conditions. In PJM, we have worked closely with PJM staff on this and prior assignments to understand RPM at a detailed level. We have also previously worked on a number of assignments with market participants from all sectors operating within the PJM footprint, which has provided us insights on how changes to the capacity market construct may impact the business decisions and other interests of suppliers, customers, utilities, and state regulators in PJM.

3. A subset of our market design work has focused on the development and improvement of capacity market demand curves designed around different sets of policy objectives. Our experience in capacity demand curve design includes: (1) prior PJM capacity market reviews in 2008, 2011, and 2014 to review market performance, including qualitative assessments and statistical simulations of the performance of the VRR Curve; (2) support of ISO-NE in the development of regional and locational system demand curves for its capacity market; (3) support of

MISO in developing a demand curve for its proposed Competitive Resource Solution; and (4) support of the Alberta Electricity System Operator in developing a capacity market demand curve for its Comprehensive Market Design**.**

4. Dr. Newell is an economist and engineer with more than 20 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and market rules. Prior to joining The Brattle Group, he was the Director of the Transmission Service at Cambridge Energy Research Associates and previously a Manager in the Utilities Practice at A.T. Kearney. Dr. Newell 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.

5. Dr. Oates has more than eight years of experience in electric power sector analysis. He has assisted clients in wholesale capacity, energy, and clean energy market design and analysis across nine electricity markets in the United States, Canada, and internationally. Dr. Oates earned a Ph.D. in Engineering and Public Policy from Carnegie Mellon University and a B.Sc. in Engineering Physics from Queen's University.

6. Complete details of our qualifications, publications, reports, and prior experiences are set forth in Exhibit No. 1 to this affidavit.

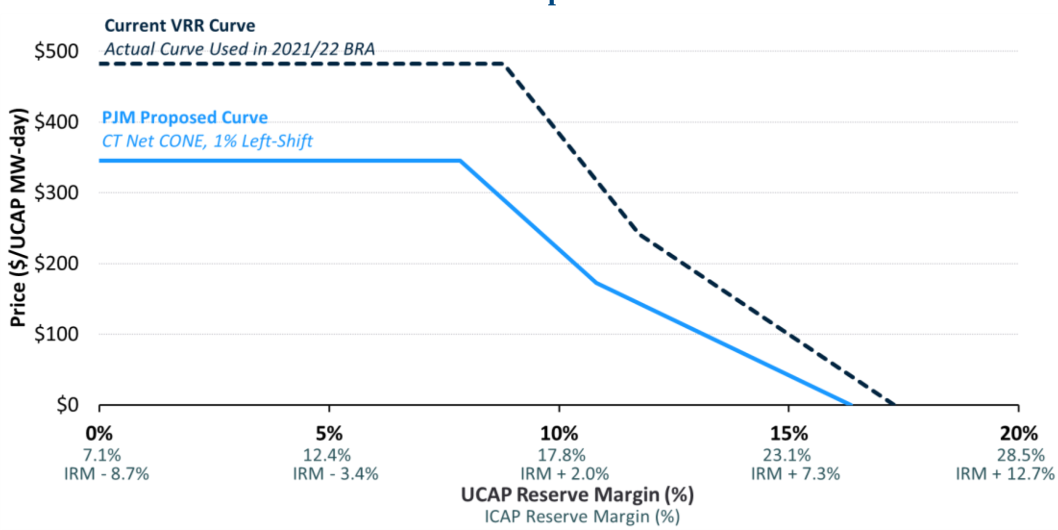
7. In July, 2017, PJM retained Brattle to help review, as required periodically under PJM's tariff, the VRR Curve used as the demand curve in RPM auctions, including key components of that curve, i.e., the gross Cost of New Entry ("CONE") parameter and the method to estimate the net revenues the CONE plant would earn in the PJM Region's energy and ancillary services markets ("EAS Offset"). The results of the CONE analysis are set forth in a separate report and supplemental materials, as shown in the affidavit that Dr. Newell is submitting concurrently with Mr. Hagerty and Mr. Gang. The results of our analysis to quantitatively and qualitatively evaluate all other parameters of the VRR Curve, and conduct a probabilistic simulation analysis of the curve's performance as required under the Tariff, are set forth in the 2018 VRR Curve Report.

8. This affidavit summarizes how the findings of the 2018 VRR Curve Report have informed PJM's proposed changes to the VRR Curve—both the EAS Offset used to determine the Net CONE parameter of the curve and the shape of the curve itself.

9. With respect to the EAS Offset, our analysis informed PJM's proposals in this proceeding to: (a) assume a ten percent adder in energy market offers for purposes of estimating energy market revenues; and (b) update the estimate of the new entry generator's Variable Operations and Maintenance ("VOM") costs that reduce the net revenues received from the energy market. The former point is suggested at page 24 of the 2018 VRR Curve report. The latter point is addressed in the separate affidavit that Dr. Newell, Mr. John M. Hagerty, and Mr. Sang H. Gang are submitting.

10. With respect to the shape of the VRR Curve, our qualitative assessment and probabilistic simulation analyses informed PJM's decision to propose the revised VRR Curve shape shown in Figure 1 in comparison with the current VRR Curve. First, PJM has adopted the significantly lower estimate of Gross CONE for a combustion turbine ("CT") plant that Dr. Newell, Mr. Hagerty and Mr. Gang address in the separate affidavit. This results in the curve overall being lower (i.e., generally assigning lower price at each level of cleared capacity) compared to the existing curve. Second, PJM agreed with our recommendation to shift the curve to the left by one percentage point of the target installed reserve margin, thus reversing a one-percent rightward shift that PJM proposed, and FERC accepted, in the last VRR Curve review proceeding. We address this leftward shift in the 2018 VRR Curve Report at pages 62–63. This leftward shift associates capacity levels with lower prices (relative to the current VRR Curve) along the portion of the curve below the price cap.

Figure 1
Current and PJM Proposed VRR Curves



Notes: The Gross CONE value reflected in PJM's Proposed Curve above is consistent with PJM's current filing, as shown in Table 1 of the separate affidavit of Dr. Newell, Mr. Hagerty and Mr. Gang. The EAS offset reflected in the above curve is consistent with the value in our 2018 VRR Curve Report and does not reflect the changes proposed by PJM in the current filing. Additionally, this EAS offset is purely indicative, as PJM would calculate the actual EAS offset and Net CONE value at a later date.

11. One component of the quadrennial review required by PJM's tariff is a probabilistic simulation analysis of the VRR Curve's performance. To conduct that probabilistic analysis, we developed a Monte Carlo simulation model that estimates the likely distribution of price, quantity, and reliability outcomes in PJM on both a system-wide and a locational basis under each analyzed demand curve. We present simulated results from 1,000 draws of potential market outcomes based on uncertainty distributions of year-to-year variation in: (a) total supply offers in the market and in each LDA, (b) supply curve shapes, (c) the reliability requirement, (d) administrative Net CONE, and (e) capacity import limit parameters. For each variable, we developed estimates of the typical magnitude of such variations based on historical data. In addition, the model assumes economically rational new entry, with new supply added infra-marginally until the long-term average price equals Net CONE.

As such, our simulations reflect long-term equilibrium conditions in a market environment where prices must be high enough to support merchant investment. The Commission has accepted and relied upon such simulations, or similar simulations, in prior PJM VRR Curve review proceedings, and in proceedings addressing capacity market demand curves for other RTOs.

12. We assessed the current, PJM-proposed, and possible alternative VRR Curves to evaluate their likely performance and consistency with the RPM design objectives. The primary objective of the VRR Curve, and of RPM itself, is to achieve the 1-event-in-10-years (1-in-10) Loss of Load Expectation ("LOLE") reliability standard on a long-term average basis (although not necessarily in every individual year). Other objectives include mitigating price volatility, reducing exposure to the exercise of market power, producing prices reflective of market conditions, minimizing complexity, and producing capacity prices that are reflective of reliability value (if possible). While not all of these objectives can be fully met simultaneously, a well-designed capacity demand curve will reflect a balance among these competing objectives. To help PJM consider this balance, our simulations yield three price/procurement-cost measurements, including average customer cost; and five measurements relative to reliability, including probability of achieving the 1-in-10 LOLE.

13. Our analysis in the 2018 VRR Curve Report focuses on a scenario where new entry occurs at our estimate of combined cycle ("CC") Net CONE, which is consistent with the observed market prices in the past several auctions that resulted in significant new entry. We also considered the reliability and cost consequences if our particular estimate of CC Net CONE were understated by 20 percent. In addition, we present an alternative scenario where long-term average entry prices gravitate toward a Net CONE based on a new CT plant, consistent with the reference technology PJM proposes in this proceeding. The results of these simulations are shown at pages 63-69 of the 2018 VRR Curve Report, including Tables 10, 11, 12, and 13. In sum, our simulations show that PJM's proposed VRR Curve satisfies the 1-in-10 LOLE standard under all conditions addressed in those tables. PJM's proposed Curve (designated as "Curve B" in those tables) meets the reliability standard while resulting in slightly lower customer capacity costs than the current VRR Curve, on the order of one percent lower customer cost.

14. We recommended in the 2018 VRR Curve Report a VRR Curve based on the estimated Net CONE of a CC plant, left-shifted one-percent (similar to PJM's proposed VRR Curve), and with a modified price cap on the left side of the curve to address a particular issue that arises when using CCs as the reference technology. That curve (designated as "Curve E" in the report) meets the 1-in-10 LOLE standard if the CC Net CONE is accurately estimated, and would further reduce customer costs compared to PJM's proposed curve (on the order of another 1.7 percent).[1] That curve

[1] These cost estimates account for only the difference in cleared capacity prices and quantities among 1,000 draws, assuming Net CONE remains the same. A more

would fall short of the 1-in-10 LOLE, however, if our estimate of the market's entry price is substantially understated, whether because CCs enter at a higher price or not at all. For example, this could be the case if investors discounted CCs' future net energy revenues and favored more flexible CTs in anticipation of a future with much higher penetration of renewable generation.

15. For the reasons given on pages 32-34 of the 2018 VRR Curve Report, we believe that there is a low likelihood that CCs will become less economic than CTs in the next several auctions. However, for reasons we discuss on page 33, we caution against switching reference technologies back-and-forth over time. This could be an argument against adopting a CC reference technology if one believes the dominant entrant technology will eventually switch to a CT. As we also stated in that report, we acknowledge an argument that a CT-based curve would more strongly guarantee resource adequacy under all conditions, at a cost that is relatively modest when put in the context of total market-wide costs.

16. This concludes our affidavit.

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comprehensive cost-benefit analysis would account for a number of factors that we have not considered, that would change with a higher reserve margin including lower energy prices and fewer scarcity and other emergency event costs.

Exhibit No. 1

Samuel A. Newell and David Luke Oates Qualifications

SAMUEL A. NEWELL
Principal

Boston, MA | +1.617.234.5725 | Sam.Newell@brattle.com

Dr. Samuel Newell is an expert in electricity wholesale markets, market design, generation asset valuation, demand response, integrated resource planning, and transmission planning, including in systems with high penetration of variable energy resources. He has 20 years of experience supporting clients throughout the U.S. in electricity regulatory, litigation, and business strategy matters. He frequently provides testimony and expert reports to Independent System Operators (ISOs), the FERC, state regulatory commissions, and the American Arbitration Association.

Dr. Newell 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.

Prior to joining The Brattle Group in 2004, Dr. Newell was the Director of the Transmission Service at Cambridge Energy Research Associates. Before that, he was a Manager in the Utilities Practice at A.T. Kearney.

AREAS OF EXPERTISE

- Electricity Market Design and Analysis
- Transmission Planning and Modeling
- Integrated Resource Planning
- Generation and Storage Asset Valuation
- Demand Response (DR) Resource Potential and Market Impact
- Gas-Electric Coordination
- RTO Participation and Configuration
- Energy Litigation
- Tariff and Rate Design
- Business Strategy

EXPERIENCE

Electricity Market Design and Analysis

- **PJM's Capacity Market Reviews**. For PJM, conducted all four official reviews of its Reliability Pricing Model (2008, 2011, 2014, and 2018). 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. Submitted testimonies before FERC and participated in settlement discussions.

- **Harmonizing New York's Wholesale Energy Market and Environmental Goals through Carbon Pricing**. Led a Brattle team to work 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.
- **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. Authored report critiquing PJM's Fast-Start proposal, which NextEra and other parties filed with 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 report with FERC.
- **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.
- **Response to DOE's "Grid Reliability and Resiliency Pricing" Proposal**. For a broad range of stakeholders opposing the rule, provided an evaluation of the proposed rule that they attached to their filing before FERC. Evaluated the need (or lack thereof) for bolstering reliability and resilience by supporting resources with a 90-day fuel supply, estimated the likely cost of the rule, and described the incompatibility of DOE's proposed solution with the principles and function of competitive wholesale electricity markets.
- **Energy Market Power Mitigation in Western Australia**. Led a Brattle team to help the Government of 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.
- **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.

- **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.
- **Buyer Market Power Mitigation**. 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.
- **Investment Incentives and Resource Adequacy 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 at the target level; and (3) evaluate options to enhance long-term resource adequacy while maintaining market efficiency. Worked with ERCOT staff to understand the relevant aspects of their operations and market data. Performed probabilistic simulation analyses of prices, investment costs, and reliability. Findings 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-authored a report estimating the economically-optimal reserve margin. Collaborated with Astrape Consulting to construct a series of economic and reliability modeling simulations accounting for uncertain weather, generation outages, and multi-year load forecasting errors. Incorporated 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, scarcity pricing provisions under the ORDC, and load-shed events.

- **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.
- **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.
- **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.
- **Capacity Auction Design for Western Australia**. For Western Australia's Public Utility Office, drafted a whitepaper and advised on the high-level design for a new forward auction-based capacity market. Subsequently drafted whitepapers and advised on auction parameters, market power mitigation, and administrative aspects of implementing a forward capacity market.

- **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.
- **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'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 extensive 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.
- **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.
- **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.
- **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.
- **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."
- **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.
- **LMP Impacts on Contracts**. For a West Coast client, 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.
- **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.

Transmission Planning and Modeling

- **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 New York. 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 in any case; reduced costs of integrating renewable resources Upstate; and tax receipts. Identified the projects with the 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.
- **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 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.
- **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.

- **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.
- **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**. For a large, geographically diverse group of clients, performed an in-depth study identifying the major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions to the bottlenecks. Worked with transmission engineers from multiple 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 highly 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 in Connecticut and Long Island.
- **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.

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 the 2008, 2009, 2010, 2012, and 2014 Plans)**. For the two major utilities in CT and the CT Dept. of Energy and Environmental Protection (DEEP), led the analysis for five successive integrated resource plans. 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.

Generation and Storage Asset Valuation

- **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 in five years. Reviewed comparables. Analyzed electricity markets in New England, New York, Texas (post-tightening of the market in 2018), 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 market-based revenue forecast for energy and capacity. Evaluated the implications of several detailed 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.

Demand Response (DR) Resource Potential and Market Impact

- **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 biggest, most cost-effective opportunities 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 the 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 the short-term energy market price impact and addressed the long-run equilibrium offsetting effects through several plausible 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. Critiqued 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

- **Demand Response Arbitration.** 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 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 nascent venture to build and operate cogen 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 their 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 large 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 potential value client could bring to each

potential customer. Worked directly with company president to translate findings into a marketing strategy.

- **Distributed Generation (DG) Market Assessment**. For the unregulated division of a major utility, performed a market assessment of DG technologies. Projected future market sizes by market segments in the U.S.
- **Fuel Cells**. For a European fuel cell component manufacturer, acted as a technology and electricity market advisor for a larger consulting team developing a market entry strategy in the U.S.

TESTIMONY and REGULATORY FILINGS

Before the Federal Energy Regulatory Commission, Docket Nos. EL16-49-000, ER18-1314-000, ER18-1314-001, EL18-178-000 (Consolidated), Affidavit of Kathleen Spees and Samuel A. Newell Regarding the Need for a Self-Supply Exemption from Minimum Offer Price and Other Policy Supported Resource Rules on behalf of Dominion Energy Services, Inc. and Virginia Electric and Power Company, October 2, 2018.

Before the Federal Energy Regulatory Commission, Docket Nos. EL17-32-000 and EL17-36-000, Prefiled Comments of Samuel A. Newell, Kathleen Spees, and Yingxia Yang on behalf on behalf of the Natural Resources Defense Council: "Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM," April 15, 2018; presented oral testimony on the Seasonality Panel at FERC's Seasonal Capacity Technical Conference on April 24, 2018.

Before the Federal Energy Regulatory Commission, Docket No. EL18-34-000, Samuel A. Newell, Pablo A. Ruiz, and Rebecca C. Carroll, "Evaluation of PJM's Fast-Start Pricing Proposal," report prepared for NextEra Energy Resources and attached to *Reply Brief of Joint Commenters*, March 14, 2018.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, oral testimony and cross examination on the electricity market impacts of the proposed Northern Pass Transmission Project, October 26-27, 2017.

Before the Federal Energy Regulatory Commission, Docket No. AD17-11-000, Prefiled Comments of Samuel A. Newell re "Reconciling Wholesale Competitive Markets with State Polices," April 25, 2017; and oral testimony on Industry Expert Panel at the Technical Conference on May 2, 2017.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Supplemental Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project--Supplemental Report," April 17, 2017.

Before the Federal Energy Regulatory Commission, Docket No. ER17-284-000, filed "Response of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," January 13, 2017.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Direct Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project," December 30, 2016.

Before the Federal Energy Regulatory Commission, Docket No. ER17-284-000, filed "Testimony of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," November 1, 2016.

"Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," Appendix 1 to Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives, Trial Staff Final Report, *Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades*, New York State Department of Public Service, Matter No. 12-02457, Case No. 12-T-0502, September 22, 2015. Presented to NYISO and DPS Staff at the Technical Conference, Albany, NY, October 8, 2015.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, filed "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Comments on LEI's June 2015 Report and Recommendations for a Regional Analysis," November 18, 2015.

Before the Federal Energy Regulatory Commission, Docket No. ER14-2940-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Variable Resource Requirement Curve," for use in PJM's capacity market, November 5, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER15-68-000, filed "Affidavit of Dr. Samuel A. Newell on behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's Minimum Offer Price Rule, October 9, 2014.

Before the Texas House of Representatives Environmental Regulation Committee, Hearing on the Environmental Protection Agency's Newly Proposed Clean Power Plan and Potential Impact on Texas, invited by Committee Chair to present, "EPA's Clean Power Plan: Basics of the Rule, and Implications for Texas," Austin, TX, September 29, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, September 25, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," September 25, 2014.

Before the Public Utilities Commission of the State of Colorado, Proceeding No. 13F-0145E, "Answer Testimony and Exhibits of Samuel A. Newell on Behalf of Tri-State Generation and Transmission

Association, Inc.," regarding an analysis of complaining parties' responses to Tri-State Generation and Transmission Association, Inc.'s Third Set of Data Requests, Interrogatory, September 10, 2014.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Analysis of the Maine Energy Cost Reduction Act in New England Gas and Electricity Markets," July 11, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve," April 1, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry For The Forward Capacity Market Demand Curve," April 1, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-616-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of ISO New England Inc.," and accompanying "2013 Offer Review Trigger Prices Study," regarding the Minimum Offer Price Rule new capacity resources in capacity auctions, December 13, 2013.

Before the American Arbitration Association, provided expert testimony (deposition, written report, and oral testimony at hearing) in a dispute involving the acquisition of a demand response company, July-November, 2013. (Non-public).

Before the Public Utility Commission of Texas, at a workshop on Project No. 40000, presented "Report On ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates Prepared By The Brattle Group," on behalf of The Electric Reliability Council of Texas (ERCOT), June 25, 2013. Subsequently filed additional comments, "Additional ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates," July 29, 2013.

Before the Federal Energy Regulatory Commission, Docket No. ER13-535-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, December 28, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-513-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC," in support of PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's capacity market, November 21, 2012.

Before the Texas House of Representatives State Affairs Committee, Hearing on the issue of resource adequacy in the Texas electricity market, presented "The Resource Adequacy Challenge in ERCOT," on behalf of The Electric Reliability Council of Texas, October 24, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "Resource Adequacy in ERCOT: 'Composite' Policy Options," and "Estimate of DR Potential in ERCOT" on behalf of The Electric Reliability Council of Texas (ERCOT), October 25, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "ERCOT Investment Incentives and Resource Adequacy," September 6, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "Summary of Brattle's Study on ERCOT Investment Incentives and Resource Adequacy," July 27, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-___-000, Affidavit of Dr. Samuel A. Newell on Behalf of SIG Energy, LLLP, March 29, 2012, Confidential Exhibit A in Complaint of Sig Energy, LLLP, SIG Energy, LLLP v. California Independent System Operator Corporation, Docket No. EL 12-___-000, filed April 4, 2012 (Public version, confidential information removed).

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, January 13, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed December 1, 2011.

Before the Federal Energy Regulatory Commission, Docket Nos. ER11-4069 and ER11-4070, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies, re: the public policy, congestion relief, and economic benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the Federal Energy Regulatory Commission, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the public policy, reliability, congestion relief, and economic benefits of the Atlantic Wind Connection Project, filed December 20, 2010.

"Economic Evaluation of Alternative Demand Response Compensation Options," whitepaper filed by ISO-NE in its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000, October 13, 2010 (with K. Madjarov).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Notice of Proposed Rulemaking regarding wholesale compensation of demand response, May 13, 2010 (with K. Spees and P. Hanser).

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2010 “Integrated Resource Plan for Connecticut” (see below), June 2010.

2010 “Integrated Resource Plan for Connecticut,” report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 4, 2010. Presented to the Connecticut Energy Advisory Board January 8, 2010.

“Dynamic Pricing: Potential Wholesale Market Benefits in New York State,” lead authors: Samuel Newell and Ahmad Faruqui at The Brattle Group, with contributors Michael Swider, Christopher Brown, Donna Pratt, Arvind Jaggi and Randy Bowers at the New York Independent System Operator, submitted as “Supplemental Comments of the NYISO Inc. on the Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure,” in State of New York Public Service Commission Case 09-M-0074, December 17, 2009.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2009 “Integrated Resource Plan for Connecticut” (see below), June 30, 2009.

2009 “Integrated Resource Plan for Connecticut,” report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 1, 2009.

“Informational Filing of the Internal Market Monitoring Unit’s Report Analyzing the Operations and Effectiveness of the Forward Capacity Market,” prepared by Dave LaPlante and Hung-po Chao of ISO-NE with Sam Newell, Metin Celebi, and Attila Hajos of The Brattle Group, filed with FERC on June 5, 2009 under Docket No. ER09-1282-000.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2008 “Integrated Resource Plan for Connecticut” and “Supplemental Reports” (see below), September 22, 2008.

“Integrated Resource Plan for Connecticut,” co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board; co-authored with M. Chupka, A. Faruqui, and D. Murphy, January 2, 2008. Supplemental Report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Department of Utility Control; co-authored with M. Chupka, August 1, 2008.

“Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI’s Proposed Demand-Side Management Programs,” whitepaper by Samuel A. Newell and Ahmad Faruqui filed by Pepco Holdings, Inc. with the Public Utility Commissions of Delaware (Docket No. 07-28, 9/27/2007), Maryland (Case No. 9111, filed 12/21/07), New Jersey (BPU Docket No. EO07110881, filed 11/19/07), and Washington, DC (Formal Case No. 1056, filed 10/1/07). Presented orally to the Public Utility Commission of Delaware, September 5, 2007.

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, "Planning Analysis of the Paddock-Rockdale Project," report by American Transmission Company re: transmission cost-benefit analysis, April 5, 2007 (with J.P. Pfeifenberger and others).

Prepared Supplemental Testimony on Behalf of the Michigan Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-718-000 et al., re: Financial Impact of ComEd's and AEP's RTO Choices, December 21, 2004 (with J. P. Pfeifenberger).

Prepared Direct and Answering Testimony on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, September 15, 2004 (with J.P. Pfeifenberger).

Declaration on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, August 13, 2004 (with J.P. Pfeifenberger).

PUBLICATIONS

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, white paper prepared for NextEra Energy Resources, October 23, 2017 (with M. Celebi, J. Chang, M. Chupka, and I. Shavel), available at http://www.brattle.com/system/publications/pdfs/000/005/530/original/Evaluation_of_the_DOE's_Proposed_Grid_Resiliency_Pricing_Rule.pdf?1509064658.

Near Term Reliability Auctions in the NEM: Lessons from International Jurisdictions. Prepared for the Australian Energy Market Operator, August 23, 2017 (with K. Spees, DL 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), available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Pricing_Carbon_into_NYISOs_Wholesale_Energy_Market.pdf

"How wholesale power markets and state environmental Policies can work together," *Utility Dive*, July 10, 2017 (with J. Pfeifenberger, J. Chang, and K. Spees), available at http://www.utilitydive.com/news/how-wholesale-power-markets-and-state-environmental-policies-can-work-toget/446715/

Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia, whitepaper prepared for the Public Utilities Office in the Government of Western 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).

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. Pefiefenberger, 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, 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, report prepared for PJM Interconnection LLC, August 26, 2011 (with J. Pfeifenberger, K. Spees, and others).

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 written for the NYISO and submitted to 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, whitepaper 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

"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," May 30, 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.

"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, February 26, 2018.

"NARUC Winter Policy Summit," presented to The Committee on Gas Panel on "Natural Gas Reliability: Understanding Fact from Fiction," 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, 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, September 30, 2014, Austin, TX.

“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, 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, 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 Jürgen 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, 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.

DAVID LUKE OATES

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Dr. David Luke Oates is an Associate at the Brattle Group with more than eight years of experience in the electricity industry. He helps clients address complex market design, analysis, and modeling questions in the context of wholesale capacity, energy, and clean energy markets. He has worked across nine electricity markets in the U.S., Canada, and internationally on behalf of a range of clients including market operators, industry stakeholders, utilities, merchant generation and transmission owners, regulators, and law firms. He has extensive experience developing and evaluating capacity market demand curves, qualification and penalty mechanisms, and other detailed capacity market design elements, having worked on behalf of PJM, MISO, IESO, and AESO.

EDUCATION

Carnegie Mellon University, Ph.D. in Engineering and Public Policy
Queen's University, Canada, B.Sc in Engineering Physics

EXPERIENCE

- **Alberta Capacity Market Design.** For the Alberta Electricity System Operator, supported the development of the Province's new capacity market. Worked with staff to develop economically-sound designs for resource qualification, market monitoring and mitigation, credit requirements, and rebalancing auctions. Performed cross-jurisdictional reviews to identify common practices and evaluated applicability to the unique Alberta context and consistency with economic principles. Developed written memos and presentations to support design development and stakeholder engagement.
- **Ontario Capacity Market Design.** For the Ontario Independent Electricity System Operator, supported the design of the Incremental Capacity Auction as part of the Market Renewal process. Worked with IESO to develop a capacity auction clearing mechanism suitable for a seasonal market design. Developed a clearing mechanism for rebalancing auctions, held between the forward auction, and supported IESO staff in presenting this material to stakeholders.
- **Ontario Non-Emitting Resources Sub-Committee Scenario Modeling.** For the Ontario Independent Electricity System Operator's Non-Emitting Resource Sub-Committee, evaluated energy, capacity, clean energy, and ancillary service market-driven investment under a range of future scenarios for Ontario's grid. Developed a dispatch and expansion model to clear all electricity markets simultaneously and accounting for Ontario's unique characteristics including high hydro and variable renewable penetration, surplus baseload, and extensive contracting. Supported a stakeholder process to develop scenarios and modeling assumptions.
- **PJM Demand Curve Performance.** For the PJM Interconnection, evaluated the performance of the capacity market demand curve relative to its design objectives and proposed a revised curve to account for changes in market conditions. Performed Monte Carlo simulation modeling of locational market clearing outcomes under a wide range of potential conditions. Evaluated the impact of Net Cost of New Entry estimates on reliability and customer costs.

- **New England Clean Energy Market.** On behalf of stakeholders in New England's Integrating Markets and Public Policy process, developed and modeled an innovative forward clean energy market design to meet state de-carbonization objectives. Worked with stakeholders to identify design objectives and identify market design elements consistent with those objectives. Developed a modeling tool to assess the impact of the proposed market design on investment decisions, carbon emissions, and customer costs.
- **Generation Asset Valuation.** For a generation owner with assets in the New York ISO, performed a fundamentals-based assessment of the going-forward value of a combined cycle plant in the context of a major re-investment decision. Considered capacity, energy, and ancillary services revenue streams under a range of future conditions. Accounted for the potential impact of state and regional carbon policies and renewable energy objectives.
- **Capacity Markets in Competitive Retail Areas**. For the Midcontinent ISO, evaluated a proposed forward capacity auction for the RTO's competitive areas. Performed Monte Carlo simulation modeling of forward and prompt auctions under a variety of conditions. Developed a recommended demand curve shape accounting for the unique mix of regulated and non-regulated assets in the MISO footprint.
- **Merchant Transmission Due Diligence.** For the potential buyer, developed revenue projections for a merchant transmission asset linking two neighboring jurisdictions. Accounted for revenue potential due to energy arbitrage between the jurisdictions, the operator's ability to capture arbitrage-driven revenues under its tariff, scheduling practices and transmission availability on the interconnecting systems, and the impact of long-term contracted transmission rights on the owners revenues.
- **Benefits of RTO Formation**. For the California ISO, studied the impacts of expanding the footprint of the ISO to include additional balancing authorities in the WECC. Analyzed benefits of RTO formation and expansion as reported in impact studies to benchmark modeled benefits of a regional RTO in the WECC.
- **Congestion Revenue Rights (CRR) Portfolio Analysis.** For a California utility, implemented a nodal model of the WECC (using PSO) to forecast congestion patterns and three-part locational marginal prices in CAISO for the following year for a number of scenarios and market conditions, e.g., low/high hydro, low/high load.
- **Transmission Scheduling**. For a transmission owner, analyzed industry practices for scheduling transmission using OASIS in the context of a dispute over access to the transmission system. Analyzed e-Tag data to evaluate the effect of changes in scheduling policies.
- **Distribution Utility Performance Incentives.** For an electric utility, benchmarked a proposed set of performance incentives for reliability, storm performance, and customer service by comparing with industry practice across North America.
- **Market Power in a Gas-Electric Merger.** Evaluated the potential for increased market power for merging electric and gas utilities. Assisted in the preparation of expert testimony before a state commission addressing the merger's potential competitive effects.

- **Spent Nuclear Fuel**. Assisted a U.S. nuclear power plant operator in assessing the damages it incurred due to the U.S. Department of Energy's delay in beginning its spent nuclear fuel collection program.
- **International Review of Demand Response Mechanisms.** Assisted the Australian Energy Market Commission with a review of wholesale Demand Response in six jurisdictions: ERCOT, Alberta, Singapore, PJM, ISO-NE, and Ontario. Reviewed and compared market rules and incentives, DR penetrations, revenues of DR providers, and energy price volatility across each market.
- **Distributed Energy Resource Effects on Distribution Utility Costs**. In the context of the New York Reforming the Energy Vision Initiative, built a model to evaluate peak reductions associated with DR, EE, and rooftop PV and associated changes in utility costs.
- **Economic and Environmental Effects of EPA's 111(d) Rule**. Constructed a multi-regional economic dispatch model of the continental United States to evaluate economic effects of state cooperation under the EPA's proposed 111(d) standard for CO_2 emissions from existing power plants. Examined the effects of states mass-based vs. rate-based compliance.
- **Effects of High Wind Penetration on Coal Cycling.** Constructed a multi-stage unit commitment and economic dispatch model to study wind integration in the United States.
- **Flexible CCS.** Constructed a price taker profit maximization model to study the economic benefits of flexible CCS. Estimated the value of CO_2 for Enhanced Oil Recovery.

TESTIMONY

Before the Federal Energy Regulatory Commission, Docket No. ER17-284-000, filed "Response of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," January 13, 2017.

PUBLICATIONS, REPORTS, AND PRESENTATIONS

"The Brattle Group's Notes on the Affordable Clean Energy Rule" (with M. Celebi, M. Chupka, M. Hagerty, and Y. Yang), report published by The Brattle Group, August 23, 2018

"Fourth Review of PJM's Variable Resource Requirement Curve" (with S. Newell, J. Pfeifenberger, K. Spees, J.M. Hagerty, J. Imon Pedtke, M. Witkin, E. Shorin), report prepared for the PJM Interconnection, April 19, 2018

"Comments on Expanding CES Eligibility to Existing Nuclear Units" (with O. Aydin, M. Celebi, T. Lee, and K. Oh), report prepared for NextEra Energy Resources and presented to the Massachusetts Department of Environmental Protection, November 30, 2017

"A Dynamic Clean Energy Market in New England" (with K. Spees and J. Chang), presentation prepared on behalf of coalition partners the Conservation Law Foundation, Brookfield Renewables, NextEra Energy Resources, National Grid, and Robert Stoddard, November 2017

"Near-Term Reliability Auctions in the NEM: Lessons from International Jurisdictions" (with K. Spees, S. Newell, T. Brown, N. Lessem, D. Jang, and J. Imon Pedtke), report prepared for the Australian Energy Market Operator, August 23, 2017

"Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California" (with J. Chang, J. Pfeifenberger, M. Geronimo, O. Aydin, K. Van Horn, L. Regan, P. Cahill, and C. McIntyre), report prepared for the California Independent System Operator, co-authored by members of the California Independent System Operator, Energy and Environmental Economics, Inc., Berkeley Economic Advising and Research, LLC, and Aspen Environmental Group, July 2016.

"Clean Power Plan in Texas: Implications for Renewables and the Electricity Market" (with K. Spees, S. Newell, and J. Mashal), presented at the 2016 Renewable Energy Law Conference, February 2016

"International Review of Demand Response Mechanisms" (with T. Brown, S. Newell, and K. Spees), report prepared for the Australian Energy Market Commission, October 2015.

"PJM Capacity Auction Results and Market Fundamentals" (with S. Newell and J. Pfeifenberger), presentation prepared for Bloomberg, September 2015.

"State cooperation under the EPA's proposed Clean Power Plan" (with P. Jaramillo), *The Electricity Journal*, vol. 28, no.3, pp.26-40, 2015.

"Profitability of CCS with flue gas bypass and solvent storage" (with P. Versteeg, E. Hittinger, and P. Jaramillo), *International Journal of Greenhouse Gas Control*, vol. 27, no. 0, pp. 279–288, Jul. 2014.

"Cycling and ramping of fossil plants, and reduced energy payments" (with W. Katzenstein), in <u>Variable Renewable Energy and the Electricity Grid</u>, RFF Press, Jun. 2014.

"Cycling Coal and Natural Gas-fired Power Plants with CCS," (with P. Versteeg, E. Hittinger, and E.S. Rubin) *Energy Procedia*, vol. 37, pp. 2676–2683, Aug. 2013.

"Production Cost and Air Emissions Impacts of Coal Cycling in Power Systems with Large-Scale Wind Penetration," (with P. Jaramillo), *Environmental Research Letters*, vol. 8, no. 2, p. 024 022, May 2013.

Exhibit No. 2

2018 VRR Curve Report

Fourth Review of PJM's Variable Resource Requirement Curve

PREPARED FOR

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April 19, 2018

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Executive Summary

The Brattle Group has been commissioned to conduct the Quadrennial Review of the Variable Resource Requirement (VRR) curve that PJM uses in its capacity market, the Reliability Pricing Model (RPM). Periodic reviews of VRR curve parameters help ensure that the RPM continues to support reliability objectives cost-effectively even as market fundamentals and technologies change. The present review will inform PJM's filing establishing the VRR curve for the next four capacity auctions, subject to annual updates. Consistent with the requirements in PJM's Tariff, our review analyzes the Net Cost of New Entry (Net CONE) and the VRR curve shape.

High-Level Conclusions and Recommendations

Net CONE represents the capacity revenue a new generator would need to be willing to enter the market. It reflects the levelized investment and fixed costs (or CONE) of an economic reference technology, minus expected net energy and ancillary service (E&AS) revenues. We estimate CONE values for natural gas-fired simple-cycle combustion turbines (CTs) and combined-cycles (CCs) in a concurrently-filed report.[1] This report evaluates PJM's E&AS estimation methodology and combines the components into indicative estimates of Net CONE. The conclusions from our Net CONE analysis are:

1. The updated estimate of Net CONE for CT plants—the current reference technology for the VRR curve as specified in PJM's tariff—is 25-42% lower than PJM's 2021/22 Net CONE parameters, depending on location.[2] The decline is driven by increased economies of scale of new H-class CTs, a lower tax rate, and a slightly lower cost of capital.
2. The updated estimate of Net CONE for CC plants—the dominant technology of new generation in PJM for more than fifteen years—is 44-76% lower than PJM's 2021/22 Net CONE parameters, and 25-63% below our updated CT Net CONE estimates, depending on location. CCs are more economic because their much higher net E&AS revenues more than offset slightly higher plant costs on a per-kW basis.
3. We propose: (a) relatively minor changes to how historical E&AS offsets are calculated for CTs; (b) a method for estimating forward-looking E&AS offsets for CCs based on futures settlement prices; and (c) a modified calculation of the RTO-wide value for Net CONE.

The shape of PJM's current VRR curve is a piecewise-linear "kinked" curve that is convex below the cap and centered approximately on a quantity defined by the installed reserve margin target and a price given by Net CONE, such that it can be expected to procure enough capacity to meet reliability objectives. We conducted probabilistic simulation analyses to evaluate the curve's ability to meet PJM's reliability objectives cost-effectively, and concluded:

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1 *PJM Cost of New Entry—Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, prepared by The Brattle Group and Sargent & Lundy, April, 2018. ("2018 CONE Study").

2 The differences across transmission zones are largely due to differences in E&AS offsets.

1. If Net CONE had not decreased significantly, the VRR curve would perform similarly to the curve filed four years ago, despite changes to the shape of the capacity supply curve associated with Capacity Performance.[3]
2. In reality, Net CONE has declined substantially, especially for CCs, and this has major implications for the VRR curve. For the VRR curve to procure enough capacity to meet and not substantially exceed PJM's resource adequacy requirements, the curve must be anchored on the price at which investors are willing to add capacity. We expect investors to continue to be willing to develop CCs at a capacity price near our estimate of CC Net CONE, and we therefore recommend that PJM adopt a CC as the reference technology for the VRR curve.
    a. If in spite of that reality, PJM maintained a CT as the reference technology for anchoring the VRR curve, continued low-priced entry of CCs would maintain average reserve margins substantially above target. Even shifting the CT-based curve 1% to the left, average reserve margins would exceed the target by 3.3% on average.
    b. If PJM adopted a CC as the reference technology, the high E&AS value for CCs would trigger the RPM's alternative price cap provision and elevate the VRR curve's price cap to Gross CONE (2.6 × Net CONE). To compensate, PJM could shift the curve 1% to the left and reduce the alternative cap to 0.7 × Gross CONE and still achieve average reserve margins 1.4% above target and exceed PJM's 1-in-10 standard unless the true cost of entry exceeds our estimate. Annual average procurement costs would be $140 million per year lower than with a left-shifted CT-based curve.
    c. We recommend adopting such a CC-based curve, reflecting the cost at which capacity is available and PJM's objective to maintain resource adequacy cost-effectively. However we also see an argument for a CT-based curve if PJM and stakeholders are highly risk-averse about ever procuring less than the target reserve margin, since the incremental cost is modest in context. Even a $140 million difference in cost is less than 0.5% of PJM's total annual wholesale costs. Overall, PJM's market-based resource adequacy construct appears to have saved much more than that by attracting and retaining a wide range of resources at competitive prices well below the estimated cost of new plants.
3. Meeting reliability objectives in the Locational Deliverability Areas (LDAs) is more challenging if Net CONE there is higher than in the RTO as a whole. To meet reliability objectives in the long run, LDA VRR curves would have to be shifted or stretched rightward and/or be subject to a price cap of at least 1.7 × Net CONE. Our recommended system VRR curve has a price cap above 1.7 × Net CONE, and no further change to the price cap would be needed if PJM applied the system curve to the LDAs, though a right-shift or stretch may still be necessary.

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[3] Capacity Performance flattens the low-priced portion of the supply curve but does not significantly affect the upper part of curve. This reduces instances of very low prices and volatility but does not change results under high-priced, low-reserve-margin conditions that drive reliability performance.

Net CONE Parameters

We reviewed all three key elements of the Net CONE calculation: (a) the levelized capital and fixed costs of new entry (CONE) for a CT and a CC plant; (b) PJM's methodology for calculating the E&AS offset for each technology in each zone; and (c) the choice of reference technology used to derive the Net CONE values that anchor the VRR curves.

CONE. As described in our separate 2018 CONE Study, updated estimates of CONE are lower than in prior studies due to increased economies of scale in H-class combustion turbines, lower corporate tax rates and, to a smaller extent, a lower cost of capital. CT CONE estimates range from \$269 to \$297/MW-day ICAP, and CC CONE estimates range from \$301 to \$329/MW-day ICAP, depending on location.[4] Table ES-1 shows "RTO CONE," which is the average of PJM's four CONE areas, and is used to establish the Net CONE parameter for the system-wide VRR curve. All estimates are based on "level-nominal" annualization of plant costs, consistent with a recent downward trend in generation costs and the prospect that new technologies and subsidized resources may reduce future capacity prices.[5] These trends suggest that annual revenue trajectories will not likely increase with inflation over the life of an asset (*i.e.*, plant revenues are more likely to remain constant in nominal dollars than in real-dollar terms).

E&AS Methodology. To inform our evaluation, we compared the Net E&AS revenues of the reference resource CCs determined using the methodology defined in the PJM tariff (*i.e.*, the "Peak-Hour Dispatch" against historical prices) to the actual net revenues earned by representative CCs. For CTs, there are too few representative existing resources to make a meaningful comparison, but we believe PJM's approach and assumptions are reasonable. Nevertheless, several refinements to PJM's current approach would more accurately reflect the variable costs and revenues of the CT and CC reference units: (1) change the assumed gas pricing points for some LDAs; (2) update the heat rates and other unit characteristics to reflect the latest technology; and (3) as long as PJM retains its current Cost Development Guidelines, move maintenance costs from variable O&M costs into the fixed O&M cost component of CONE. These recommended changes reduce variable costs and tend to increase the Net E&AS revenue offset, which decreases Net CONE. We also recommend that PJM include an estimate of any net Capacity Performance bonus payments for the reference units when setting future Net E&AS revenue offsets.

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4 These values are presented on an ICAP basis and count major maintenance costs as variable costs. If they are instead counted as fixed costs, the CT CONE estimates would range from \$325 to \$348/MW-day and CC CONE estimates would range from \$328 to \$360/MW-day. See 2018 CONE Study.

5 Our analysis does not explicitly account for PJM's proposed reforms to capacity market pricing related to state policy-supported resources and the Minimum Offer Price Rule; we assume that, with or without the proposed reforms, long-term average prices have to be high enough to support in-market entry by gas-fired generation. Our level-nominal CONE calculation accounts for the possibility that long-term prices eventually decline as other technologies enter at a lower net cost of capacity.

As in past reviews, we conclude that forward-looking estimates of E&AS revenues would better represent the expectations of generation developers and thus yield a VRR curve that meets reliability objectives more effectively than relying on historical estimates. In this report, we recommend an approach to estimate forward-looking net E&AS revenues for CC plants. CCs' ability to earn energy margins can be approximated by simple dispatch of the plants during all "5 × 16" on-peak hours (with a slight adjustment to account for actual units being able to optimize better, including by operating in some off-peak hours). This approach uses on-peak futures prices to estimate forward-looking net E&AS revenues for CC plants. Although futures are not liquid beyond one year and do not cover all locations, we propose an approach to extend the available market data further forward and to other locations. This approach does not work well for CT plants, however, because their dispatch does not closely match any observable forward-traded product. We did not identify an alternative for CTs that is superior to the historical approach.

We recommend that PJM consider additional changes to developing its Net CONE value for the RTO-wide VRR Curve. RTO Net CONE is currently calculated by deducting an E&AS offset based on a system-wide average electricity price and a representative zone gas price from the average of Gross CONE in the four CONE areas. We recommend that PJM instead set the RTO E&AS offset at the median of all of the individual LDAs' E&AS offsets. Similarly, we recommend that PJM set the E&AS for each multi-zone LDA (e.g., MAAC, EMAAC) at the median of all of the individual LDAs' E&AS offsets within the multi-zone LDA. Using E&AS margins available in an actual LDA will ensure that the electricity prices are consistent with the gas prices, avoiding false spreads that are not available to any real generator. Using the median will provide somewhat more stability than an average, which can be affected by individual LDAs with substantially higher or lower E&AS offsets than the rest of the system in any given year.

Net CONE. Net CONE is calculated as CONE minus the E&AS offset. Table ES-1 below shows our indicative RTO-wide Net CONE estimate compared to the parameters PJM recently posted for its next BRA (for 2021/22 delivery).[6] We say "indicative" because the scope of our assignment includes estimating Gross CONE values, which does not require estimating E&AS offsets. Our assignment was to review PJM's E&AS *methodology* rather than establish the E&AS values themselves. PJM will have to develop the E&AS values based on the methodological refinements it will implement for the next BRA. The E&AS values we present are only indicative estimates for use in our review of the VRR curve performance.

The indicative E&AS estimates shown for CTs are based on simulations provided by PJM staff, using historical prices from 2015 through 2017. These estimates do not account for any of our recommended refinements and continue to treat major maintenance costs as a variable cost. The values shown for CCs are based on our application of the forward-looking approach we

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[6] There is no RTO-wide CC Net CONE BRA parameter.

recommend for CCs; they account for the 6,300 Btu/kWh heat rate and lower variable O&M of the new CC technology.[7]

Table ES-1
RTO-Wide Net CONE Estimates (Nominal Dollars)

		2021/22 BRA	2022/23 Brattle Estimate	
		CT	CT	CC
Gross CONE	*$/MW-year ICAP*	$135,300	$104,200	$114,400
E&AS Margin	*$/MW-year ICAP*	$24,800	$28,400	$70,600
Net CONE	*$/MW-year ICAP*	$110,500	$75,800	$43,800
Net CONE	***$/MW-day UCAP***	**$322**	**$222**	**$129**

Sources and notes:
2021/22 BRA values taken unadjusted from 2021/22 BRA parameters, PJM (2018).
Brattle estimated RTO-wide E&AS are based on the median of all LDAs. Gross CONE values reflect the average of the CONE values in each of the four CONE areas.
Brattle estimates are converted from ICAP to UCAP using 2020/21 BRA EFORd rate.
Major maintenance costs are included in variable O&M (VOM).

Choice of Reference Technology for VRR Curve. Our Net CONE estimate for CC plants and our recommendation to use CCs as the reference technology is supported by empirical data showing large quantities of CCs entering the market at prices consistent with our estimates. CCs have been the overwhelming choice of actual new generation development over the last several years, and nearly 27,000 MW of new combined-cycle generation has cleared PJM's capacity auctions since then (*i.e.*, in auctions for delivery in 2015/16 through 2020/21). These CC plants have entered the market at clearing prices 50-80% below PJM's CT-based Net CONE estimates.[8] As a result, the cleared quantities in the PJM capacity auctions have exceeded the PJM reserve margin target by 3 to 6 percentage points.[9]

Other considerations for selecting a reference technology include the hazard of switching technologies used in a long-term construct, E&AS estimation error for CCs vs. CTs, year-to-year variability in E&AS for CCs vs. CTs. We show in Section II.E that none of these factors substantially disfavors switching to a CC.

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[7] The forward-looking E&AS margins based on the updated CC heat rate and variable O&M are similar to PJM's historical simulations using the current specifications because the lower operating costs of the updated CC reference technology are offset by lower electricity futures prices.

[8] Based on RTO clearing prices and Net CONE parameters. See Table 8, PJM (2017d). The 2017 State of the Market report shows that market revenues in 2017 would have provided CCs with 100% of Gross CONE in three zones and 90% in 11 zones. See Monitoring Analytics (2017). With our lower CC Gross CONE estimates, new entrants would have covered their costs in the RTO and in 12 zones.

[9] Calculated for RTO-wide cleared quantities. See PJM (2017d).

System VRR Curves

VRR curves serve as the demand curve for PJM's capacity auctions. They are intended to procure enough capacity to meet PJM's resource adequacy requirements. The VRR curves are downward-sloping and anchored to a reference point at a price given by Net CONE and a quantity given by the installed reserve margin target, but shifted slightly rightward. Such curves accommodate inevitable fluctuations in supply, demand, and transmission, in several ways that a vertical capacity demand curve would not: (1) the slope recognizes that capacity has lower (but non-zero) incremental value above the target reserve margin and higher value below; (2) the slope reduces price volatility as market conditions fluctuate; (3) the slope mitigates potential market power; and (4) the rightward shift adjusts for the asymmetric reliability consequences of capacity deficits versus excesses, such that resource adequacy targets can be met on average and years with unacceptably-low reserve margins are largely avoided. The exact slope, shape, and shift of the curve have been developed to achieve reasonable tradeoffs between meeting resource adequacy requirements without too much excess capacity or too much price volatility. PJM's periodic reviews of VRR curve performance, such as this one, re-assess these tradeoffs and inform PJM's updating of the VRR curve parameters and shape to maintain acceptable performance as market conditions and technologies evolve.

To evaluate PJM's current VRR curve and possible alternatives, we conducted Monte Carlo simulations using an updated and enhanced version of the model that we used in the 2014 Review.[10] The model evaluates capacity market outcomes probabilistically, given realistic fluctuations in supply, demand, and transmission, and under the long-run equilibrium assumption that merchant generation will enter the market until average prices equal Net CONE. In this Quadrennial Review, we first updated the model to account for recent changes in system supply, demand, transmission, LDA topology, and the effect of PJM's new Capacity Performance (CP) market design.[11] We find that these updates have only a minor impact on simulated VRR curve performance relative to the results from our 2014 Review, assuming the Net CONE value used to anchor the VRR curve is equal to the actual price at which developers will enter the market. Significant performance differences arise if that assumption does not hold.

We evaluate the performance of several candidate VRR curves accounting for the reduction in the market entry price, as illustrated in Figure ES-1 alongside PJM's current VRR curve from the 2021/22 auction (**dark blue** dashed line). Table ES-2 reports the performance results of the candidate curves. In evaluating these candidate VRR curves, we assumed that CCs continue to enter the market consistent with our estimate of CC Net CONE.

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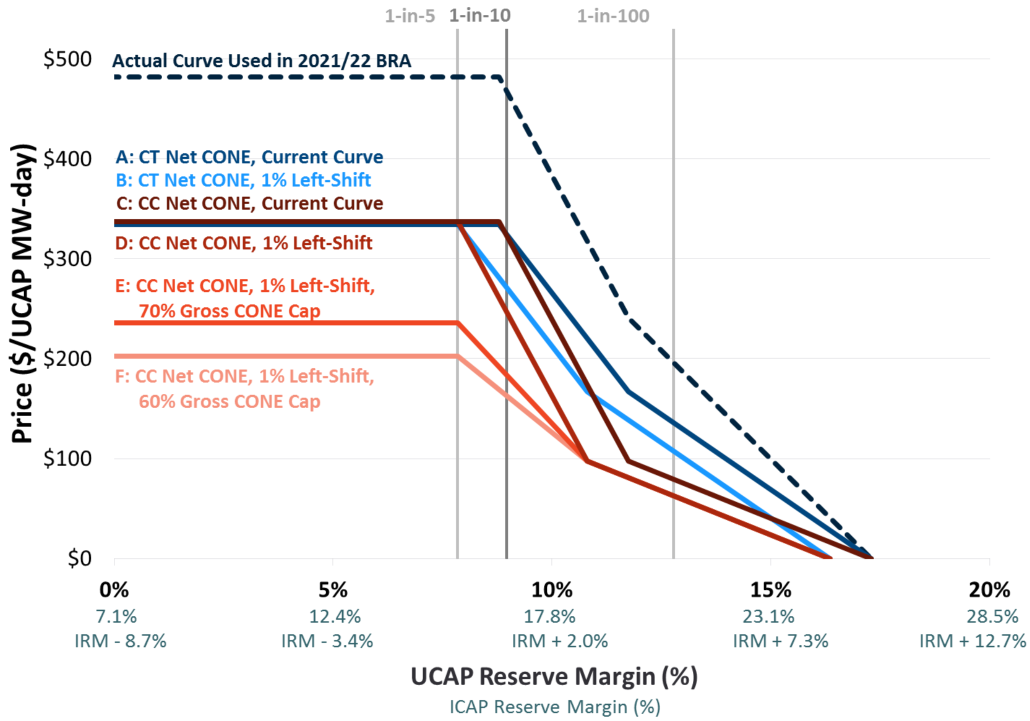
10 We do not re-evaluate the basic shape of the demand curve in this review. Our 2014 Review included an extensive discussion of the basis for the shape of PJM's VRR curve. See Pfeifenberger *et al.* (2014).

11 Capacity Performance has made the lower half of the capacity market supply curves more elastic, which helps reduce price volatility and slightly improve reliability.

Figure ES-1
Candidate System VRR Curves



Notes and Sources:

CC and CT curves are based on the level-nominal estimates of Gross CONE with major maintenance in VOM, our recommendation to use the median LDA E&AS margin as the RTO value, and apply PJM's backward-looking E&AS methodology for the CT estimate and forward-looking approach for the CC estimate.

2021/22 BRA curve uses unadjusted values posted in the 2021/22 BRA parameters, PJM (2018).

The candidate demand curves shown in Figure ES-1 include:

A. **Current VRR Curve with Updated CT Net CONE** (shown in blue) remains high relative to the lower costs at which CCs enter, so long-run reserve margins exceed the Installed Reserve Margin (IRM) target by 4.3% on average.

B. **1% Left-Shifted Curve with CT Net CONE** (shown in light blue) undoes the 1% right-shift that PJM implemented four years ago based partly on concerns about market and regulatory uncertainties at the time.[12] This reduces excess capacity, but still averages 3.3% above target with an expected LOLE of 0.023 vs. a looser requirement of 0.1.

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12 We understand that PJM right-shifted the curve we had recommended, in part because of drivers of acute short-term supply uncertainty that may not have been fully captured in our modeling, including Mercury Air Toxics Standards (MATS) retirements, low gas prices, EPA's Clean Power Plan, and the D.C. Circuit Court's *vacatur* of FERC Order 745. Many of these are no longer a concern. While we acknowledge the ongoing potential for retirement by plants not covering their fixed costs, economic retirements do not pose the same resource adequacy challenge as the risk of *simultaneous* large-scale retirements under MATS. PJM's market has demonstrated its ability to manage economic retirements by attracting new capacity or incentivizing incumbents to stay online as the market tightens.

C. **Current VRR Curve with Updated <u>CC</u> Net CONE** (shown in **dark red**) recognizes the availability of low-cost CC entry, but CCs' high E&AS offset triggers RPM's alternative price cap of Gross CONE (=2.6 × Net CONE) and stretches the left half of the curve upward. Excess capacity is further reduced but still yields an expected LOLE of 0.031, over three times better than the resource adequacy standard.

D. **1% Left-Shifted Curve with CC Net CONE** (shown in **medium red**) undoes the 1% right-shift, similar to curve B. Expected reliability still beats the LOLE target by a factor of 2 due to the high price cap.

E. **1% Left-Shifted Curve with CC Net CONE and Alternative Price Cap at 0.7 × Gross CONE** (shown in **red**) more tightly meets with resource adequacy objectives, with average reserve margins just 1.4% above IRM and with an average LOLE of 0.071. However, if the market entry price were 20% higher than the estimated value used to anchor the VRR curve, average LOLE would be 0.163, about 60% worse than the requirement.

F. **1% Left-Shifted Curve with CC Net CONE and Minimum Price Cap at 0.6 × Gross CONE** (shown in light red) more precisely meets the 0.1 LOLE target in expectations, but performs precipitously worse if the market entry price is 20% higher than estimated.

Table ES-2
Simulated Performance of Candidate System VRR Curves
*Assuming Market Entry Occurs at Our Estimated CC Net CONE of $129/MW-day**

	Admin Net CONE	Price and Procurement Costs			Reliability					
		Avg. Price (= Market Entry Price)	Standard Deviation of Price	Average Cost (P × Q)	Average LOLE	Stress LOLE *	Average Excess (Deficit)	Reserve Margin Standard Deviation	Frequency Below Reliability Requirement	Frequency Below 1-in-5
	($/MW-d)	*($/MW-d)*	*($/MW-d)*	*($mil)*	*(Ev/Yr)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*
CT as Reference Technology										
A: Current Curve	$222	$129	$34	$8,139	0.011	0.023	4.3%	1.1%	0%	0%
B: 1% Left-Shift	$222	$129	$34	$8,065	0.023	0.041	3.3%	1.1%	0%	0%
CC as Reference Technology										
C: Current Curve	$129	$129	$58	$8,039	0.031	0.046	2.8%	1.1%	1%	0%
D: 1% Left-Shift	$129	$129	$58	$7,969	0.053	0.072	1.8%	1.1%	5%	0%
E: 1% Left-Shift, 70% Gross CONE Cap	$129	$129	$50	$7,927	0.071	0.163	1.4%	1.5%	15%	4%
F: 1% Left-Shift, 60% Gross CONE Cap	$129	$129	$46	$7,906	0.091	0.331	1.1%	1.7%	20%	6%

Notes:
Prices are reported in dollars per UCAP MW per day.
Gross CONE values used in the simulation modeling are trivially (<1%) different from the final values developed in our CONE study.
* "Stress LOLE" assumes the realized market entry price exceeds our estimated CC Net CONE by 20%.

Based on this analysis, we recommend anchoring the VRR curve on CC Net CONE, shifting the curve 1% left and reducing the alternative price cap to 0.7 × Gross CONE (curve **E**). Simulated reliability meets the LOLE requirement, with a reserve margin exceeding the target IRM 85% of the time, assuming administrative Net CONE reflects the true price developers need to enter. If the true cost were 20% higher, reliability would fall short of the target, but not nearly as much as with the curve with the lower cap.[13] Annual average procurement costs are $140 million lower relative to the left-shifted CT-based curve (curve **B**), suggesting that the recommended curve represents a reasonable tradeoff between cost and performance under adverse conditions.

Locational VRR Curves

Resource adequacy in the import-constrained LDAs depends on transmission and can be strongly affected by fluctuations in import limits and supply that are large in percentage terms. When reserve margins tighten and import constraints bind, the LDA capacity clearing price rises above the parent area's price; but when local reserve margins are high, the LDA price will fall only as far as the clearing price in the parent zone. This asymmetric exposure helps to attract local supply and support resource adequacy. However, LDAs with significantly higher Net CONE than their parent areas will have to price-separate above the parent zone more frequently in order for average clearing prices to cover the Net CONE premium, with lower reliability in those instances.

Our analysis of VRR curves for the LDAs focuses on these dynamics, rather than the impact of recent low market entry prices and the choice of reference technology. We simply assume that in each location, administrative Net CONE and the market entry price are always equal to each other, given by the 2020/21 BRA parameters. With this core assumption, we explore the impact of potential future conditions in which LDA Net CONE values are similar to today and, alternatively, in which they increase relative to parent zones.

For the VRR curves in LDAs, our simulations show that the updated current curve is expected to meet resource adequacy requirements under our base assumptions—but not under potential alternative future conditions. PJM's locational resource adequacy standard requires that each LDA achieves a long-run average LOLE of 1-in-25 or better (0.04 events per year).[14] Under our base assumptions with locational Net CONE values consistent with the 2020/21 BRA, most LDAs have lower Net CONE than the parent zones. Under these conditions, LDAs easily meet the reliability standard because costs are lower while capacity prices in LDAs cannot fall below the prices in parent areas in PJM's nested, import-constrained topology.

We are concerned, however, that LDA Net CONE values may not remain below those in the parent areas in a long-run equilibrium where increased entry in the LDAs reduces E&AS offsets and increases Net CONE there. If LDA Net CONE values were to exceed the parent LDA level, a price premium would be needed to attract local investments. In addition, these investments would face relatively high volatility in supply, demand, and transmission within the LDAs,

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13 We also evaluated the impact of lowering the alternative price cap to 0.8 × Gross CONE, which achieves expected LOLE of 0.061, and 0.105 in the "stress case."

14 The 1-in-25 LOLE target for LDAs is conditional on perfect reliability in the parent zone. See PJM (2017g), Section 2.2.

which would increase resource adequacy challenges. If Net CONE were to become 5% higher in each LDA compared to its parent LDA, we estimate that five of the fourteen LDAs would fail to meet the 1-in-25 LDA standard. If Net CONE values in the LDAs were 20% above their parent LDA levels, ten LDAs would fail to achieve the 1-in-25 LDA standard.

To address this resource adequacy risk, we evaluate two refinements to the locational VRR curves. First, ensuring that the locational demand curves have price caps of at least 1.7 × Net CONE would mitigate the risk of falling below LDA resource adequacy requirements by allowing more supply to clear whenever the market is short. If PJM adopts our recommended system curve based on CC Net CONE, with a 1% left-shift and 70% Gross CONE price cap (curve **E** in Figure ES-1), the price cap would be approximately 1.8 × Net CONE. No further change would be needed to the cap if this curve were applied at the local level. Second, establishing a minimum demand-curve-width of 25% of the Capacity Emergency Transfer Limit (CETL) would help mitigate the impact of CETL variability in small LDAs. This minimum curve width could be applied to local curves of the same shape as any of the candidate system curves.

We estimate that both of these measures would individually improve resource adequacy in the LDAs, but would still not quite achieve the 1-in-25 standard in all zones under market conditions in which LDAs' Net CONE values are 5% higher than in the parent areas. When the two measures are combined, however, the 1-in-25 standard is achieved in all LDAs. We therefore recommend that PJM consider adopting both of these measures.

In addition to our recommended changes to the LDA curves, we identified some potential improvements to closely-related market design elements that may mitigate price volatility or better align prices with locational reliability value. These include: (1) defining local reliability objectives in terms of normalized unserved energy; (2) generalizing the approach to modeling locational constraints in RPM beyond import-constrained, nested LDAs with a single import limit; (3) reviewing options for increasing the predictability and stability of CETL estimates; and (4) revising the auction-clearing mechanics to produce prices that are more proportional to the marginal reliability value of incremental resources in each LDA.

I. Background

In this study, we assess the parameters and shape of PJM Interconnection, LLC's Variable Resource Requirement (VRR) curve, which is used to procure capacity under the Reliability Pricing Model (RPM). This Background section provides an overview of the structure of RPM and the VRR curve, as well as references to more detailed documentation as available in PJM's Tariff and manuals.[15]

A. Study Purpose and Scope

We have been commissioned by PJM to evaluate the parameters and shape of the administrative VRR curve used to procure capacity under RPM, as required periodically under the PJM tariff.[16] The purpose of this evaluation is to assess the effectiveness of the VRR curve in supporting the primary RPM design objective of maintaining resource adequacy at the system and local levels, as well as other performance objectives such as mitigating price volatility and susceptibility to the exercise of market power. Our study scope includes: (1) estimating the Cost of New Entry for each Locational Deliverability Area; (2) reviewing the methodology for determining the Net Energy and Ancillary Services Revenue Offset; and (3) evaluating the shape of the VRR curve. This report documents our analysis and findings for the second and third topic areas and summarizes our analysis for the first. Our estimate of the Cost of New Entry is contained in a separate report. [17]

Under the first two Triennial Reviews, we assessed the overall effectiveness of RPM in encouraging and sustaining infrastructure investments, reviewed auction results over the first eight Base Residual Auctions (BRAs) and first seven Incremental Auctions (IAs), analyzed the effectiveness of individual market design elements, and presented a number of recommendations for consideration by PJM and its stakeholders. The results of these prior assessments are presented in our June 2008 and August 2011 reports reviewing RPM's performance ("2008 RPM Report" and "2011 RPM Report").

The scope of this study, like our 2014 study ("2014 RPM Report"), is more narrowly focused on the items identified in the tariff than our 2008 and 2011 RPM Reviews. It does not include a review and summary of RPM auction results, solicitation of stakeholder input, or an evaluation of other RPM parameters beyond CONE, the E&AS offset, and the VRR curve.

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15 As the authoritative sources documenting the structure of RPM, see Attachment DD of PJM's Tariff, and Manual 18, PJM (2017f, 2017h).

16 See PJM Tariff, Attachment DD.5.10.a, PJM (2017h).

17 *PJM Cost of New Entry—Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, prepared by The Brattle Group and Sargent & Lundy, April 2018 ("2018 CONE Study").

Finally, our analysis does not explicitly account for PJM's proposed reforms to capacity market pricing related to state policy-supported resources and the Minimum Offer Price Rule. We assume that, with or without the proposed reforms, long-term average prices have to be high enough to support in-market entry by gas-fired generation. Our level-nominal CONE calculation (instead of level-real) accounts for the possibility that prices eventually decline in real terms as other technologies enter at a lower net cost of capacity.

B. OVERVIEW OF PJM'S RELIABILITY PRICING MODEL

The purpose of RPM is to attract and retain sufficient resources to reliably meet the needs of consumers at all locations within PJM, through a well-functioning market. It has been doing so since its inception in 2007/08. RPM is now entering its fifteenth delivery year of experience, with the next auction scheduled for May 2018 to procure capacity for the 2021/22 delivery year.

RPM is a centralized market for procuring capacity on behalf of all load, with all capacity procured through BRAs conducted three years prior to delivery and adjustments to load forecasts and supply settled through shorter-term IAs. The costs of these capacity procurements are allocated to load serving entities (LSEs) throughout the actual delivery year. "Demand" in PJM's auctions is described by the VRR curve, a segmented, downward-sloping, convex curve that is designed to procure enough capacity to meet resource adequacy objectives while avoiding the extreme price volatility that a vertical curve might produce. Recognizing transmission constraints, each of several nested LDAs has its own VRR curve that may set higher prices locally if transmission constraints bind in the auction.

On the supply side, a diverse set of existing and new resources compete to sell capacity under RPM, including traditional and renewable generation, demand response, energy efficiency, storage, qualified transmission projects, and imports. Existing resources are required to submit an offer, subject to market monitoring and mitigation. Some types of new resources are also monitored to ensure they are being introduced at competitive levels that do not artificially suppress prices. With the introduction of Capacity Performance, all capacity sellers must be available across the full delivery year. Resources available only in one season may still participate by pairing up with an opposite-season resource ahead of the auction, or by allowing PJM's auction clearing mechanism to find a suitable match. Capacity Performance has considerably strengthened penalties charged to non-performing resources and has introduced bonuses for resources that perform better than expected.

RPM allows for self-supply arrangements, whereby entities with load-serving obligations can sell supply into the auction and earn revenues that offset the load's payments on the demand side. RPM has an opt-out mechanism in which self-supply utilities can meet a Fixed Resource Requirement (FRR) instead of a variable requirement.

Attachment DD of PJM's Open Access Transmission Tariff (OATT) and PJM's Manual 18 describe in greater detail these and other features of the RPM market design.[18] Additional documentation on the parameters and performance of PJM's RPM include: (a) PJM's planning period parameters and auction results; (b) our 2008, 2011, and 2014 RPM performance Reviews; and (c) performance assessments of PJM's Independent Market Monitor (IMM), as documented in annual State of the Market Reports, assessments of individual auctions' results, and other issue-specific reports.[19]

C. Description of the Variable Resource Requirement Curve

In our 2014 RPM Review, we recommended that PJM adopt a downward-sloping, convex VRR curve, set to achieve 0.1 LOLE on average in the long run. At lower reserve margins, additional supply brings substantial improvement in reliability due to the steepness of the LOLE curve in this region, as shown in Figure 16. At higher reserve margins, additional supply brings relatively less improvement. The convex shape quickly pays more for supply when the market is short and more gradually reduces prices as the market becomes long, aligning prices with the reliability value of incremental supply. In addition, the convex curve tends to produce a distribution of market prices that is more consistent with those of other commodity markets, with a fatter tail on the high-price side. Perhaps most importantly, a convex curve is more robust from a quantity perspective, with changes to Net CONE or errors in Net CONE producing smaller reliability deviations from the resource adequacy target than straight-line or concave curves.

Following our 2014 Review, PJM proposed, and the Federal Energy Regulatory Commission (FERC) accepted, a convex VRR curve that was right-shifted by 1% relative to our recommended curve. PJM pointed out that while our recommended curve achieved 0.1 LOLE on average, it frequently resulted in low reliability outcomes below the 1-in-5 LOLE level (13% of the time) and did not perform well under adverse conditions (*e.g.*, larger than expected fluctuations in net supply, administrative under-estimation of Net CONE). PJM's right-shifted convex VRR curve reduced the likelihood of outcomes below the 1-in-5 level to 7% and performed well under adverse conditions, while only increasing customer costs by 1% in our simulations.[20]

The prices and quantities of the VRR curve are premised on the assumption that, in a long-term economic equilibrium, prices need to be at Net CONE on average to attract new entrants when needed for reliability. Net CONE is the first-year capacity revenue a new generation resource would need (in combination with expected E&AS margins) to fully recover its capital and fixed costs, given reasonable expectations about future cost recovery over the asset life. The price at each point on the VRR curve is indexed to Net CONE. The price cap is well above Net CONE

18 See PJM (2017f, 2017h).

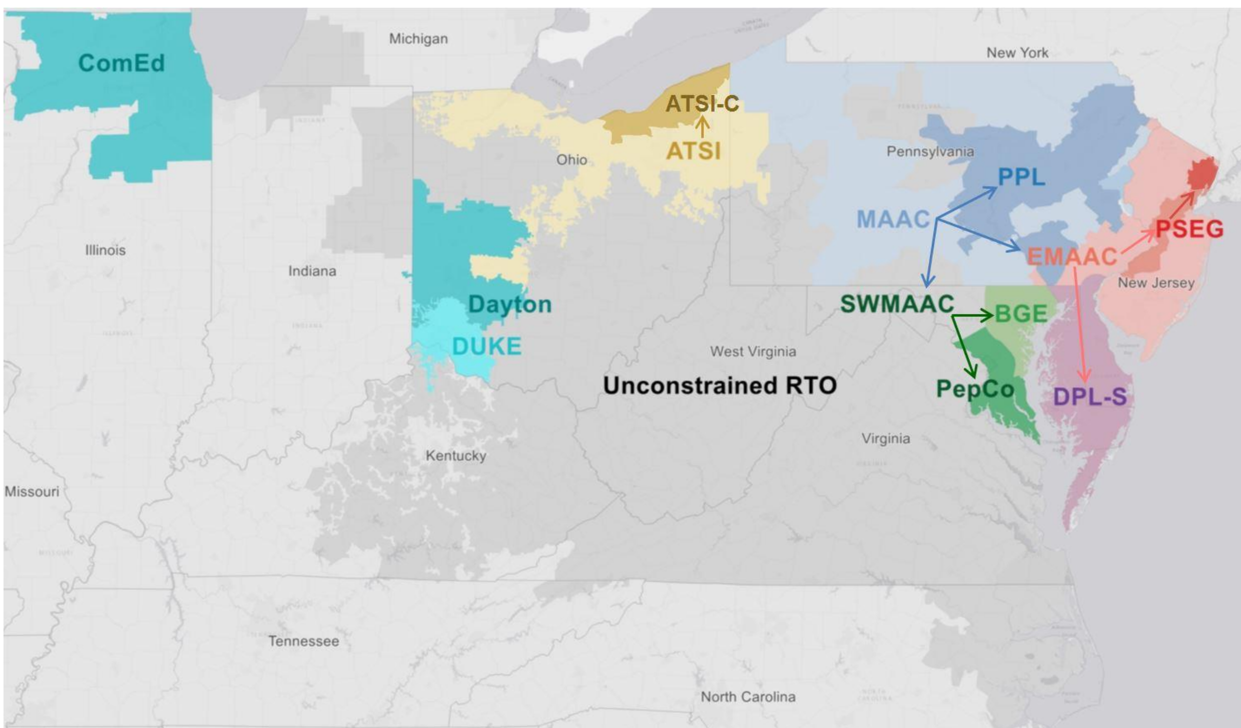
19 See PJM Planning Period Parameters for the years 2007–2017, Pfeifenberger (2008, 2011, 2014). For PJM State of the Market and periodic reports on RPM, see Monitoring Analytics (2014, 2017).

20 See PJM (2014f).

(1.5 × on PJM's current VRR curve), the kink is somewhat below Net CONE (0.75 × on PJM's current VRR curve), and the foot is at a price of zero. In order to account for variability and to achieve the resource adequacy requirement (quantity needed to meet the 1 event in 10 years, or 1-in-10, LOLE standard) on average, the VRR curve quantity is greater than the desired average reserve margin at a price of Net CONE. Prices decline as reserve margins increase and rise as reserve margins decrease, but all price points on the curve are indexed to Net CONE.

At the local level, individual VRR curves are applied to each LDA based on the local resource adequacy requirement and locally estimated Net CONE. Modeled LDAs are sub-regions of PJM with limited import capability from their parent due to transmission constraints. If an LDA is import-constrained in an RPM auction, locational capacity prices will exceed the capacity price in the parent LDA. Currently there are 27 possible LDAs defined in RPM (including the RTO), although only 15 LDAs are modeled and could yield different clearing prices in the 2020/21 delivery year. Figure 1 is a map of these modeled LDAs. Figure 10 in Section III.B shows the nested LDA structure as modeled in RPM with sub-LDAs having equal or greater clearing price than all parent-level LDAs.

Figure 1
Map of Modeled Locational Deliverability Areas



Sources and Notes:
Map created with SNL Energy (2017); map reflects modeled LDAs as of 2020/21, PJM (2017c).

II. Net Cost of New Entry Parameter

Net CONE is determined as 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. We examine PJM's current conditions and recent new installed capacity and conclude the following:

- Net CONE for a gas-fired combustion turbine (CT)—the current reference technology for the VRR curve as specified in PJM's tariff—is now 25-42% lower than PJM's 2021/22 Net CONE parameter, depending on location.[21] The decline is primarily driven by the economies of scale of new H-class CTs, the lower corporate tax rate and, to a lesser extent, a slightly lower cost of capital.
- Net CONE for gas-fired combined-cycles (CCs)—the dominant technology of new generation in PJM for more than fifteen years— is 44-76% lower than PJM's 2021/22 CT-based Net CONE parameter, and 25-63% below the updated CT Net CONE estimate, depending on location. This difference is mostly due to the much higher E&AS revenues of CCs and plant costs that are only slightly higher than those of CTs on a dollar-per-kW basis.
- Based on the economic advantage of CCs over CTs and the prevalence of CCs in new generation investments in the PJM market, we recommend that PJM consider adopting the CC as the reference technology for anchoring the VRR curve.
- We also propose relatively minor changes to the way historical E&AS offsets are calculated for CTs, a method for estimating forward-looking E&AS offsets for a CC based on on-peak futures settlement prices, and a different averaging technique for calculating the RTO-wide value for Net CONE.

A. Updated Gross 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 1 summarize our CONE estimates for gas CT and CC plants in each of the four PJM CONE Areas for the 2022/23 delivery year.[22] Detailed documentation of these CONE estimates and our study approach is provided in our separate CONE study.[23]

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21 The differences across zones are largely due to differences in the net E&AS revenue offset.

22 Previous CONE studies had five CONE Areas, but the Dominion CONE Area was removed in recent tariff changes and is now included in the Rest of RTO CONE Area.

23 See Newell *et al.* (2018).

Table 1
2022/23 CONE Values and Comparable Values from 2021/22 BRA

	Simple Cycle ($/ICAP MW-year)				Combined Cycle ($/ICAP MW-year)			
	EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
2021/22 Auction Parameter	$133,144	$140,953	$133,016	$134,124	$186,807	$193,562	$178,958	$185,418
...Escalated to 2022/23	$136,900	$144,900	$136,700	$137,900	$192,000	$199,000	$184,000	$190,600
Updated 2022/23 CONE	**$106,400**	**$108,400**	**$98,200**	**$103,800**	**$116,000**	**$120,200**	**$109,800**	**$111,800**
Difference from Prior CONE	-22%	-25%	-28%	-25%	-40%	-40%	-40%	-41%

Sources and Notes:

All monetary values are presented in nominal dollars.

2021/22 auction parameter values based on Minimum Offer Price Rule (MOPR) Floor Offer Prices for 2021/22 BRA. PJM 2021/22 parameters escalated to 2022/23 by 2.8%.

All monetary values are presented in nominal dollars.

CONE includes major maintenance costs in variable O&M costs. Alternative values with major maintenance costs in fixed O&M costs are presented in Appendix C of the CONE Study.

Three factors drive most of the decrease in CONE:

- **Economies of scale on larger combustion turbines.** Selection of GE 7HA.02 turbines reflects a recent trend toward larger turbines. The GE H-class turbines are sized at 320 MW per turbine compared to 190 MW for F-class turbines in 2014; the capacity of a 2x1 CC plant nearly doubles from 650 to 1,140 MW.[24] This lowers both construction labor and equipment costs on a per-kW basis. As such, the current overnight capital costs for a CT are only $799/kW to $898/kW (depending on location), 2-10% lower than the 2014 estimates of $890/kW to $927/kW escalated forward to 2022.[25] CC capital costs range from $772/kW to $873/kW, about 25% lower than the 2014 estimates of $1,054/kW to $1,127/kW escalated to 2022.
- **Reduced federal taxes.** The tax law passed in December 2017 reduced the corporate tax rate to 21% and temporarily increased bonus depreciation to 100%, although it eliminated the state income tax deduction. These changes decrease the CT CONE by about $21,000/MW-year (17% lower) and the CC CONE by about $25,000/MW-year (18% lower), before accounting for the higher cost of capital due to the lower tax rate.
- **Lower cost of capital.** We estimate an after-tax weighted-average cost of capital (ATWACC) of 7.5% for merchant generation based on current and projected

[24] The max summer capacity is based on the estimated values for the Rest of RTO CONE Area.

[25] We compare the current capital cost estimates to those filed by PJM in the 2014 CONE update. We escalated the 2018 capital costs to 2022 by first applying the location-specific escalation rates PJM used for the 2019/20, 2020/21, and 2021/22 CONE updates for the first three years and then escalating the costs an additional year by 2.8%/year based on cost trends in labor, equipment, and materials inputs.

capital market conditions and the change in the corporate tax rate (which varies slightly across locations due to differences in state tax rates). Compared to an ATWACC of 8.0% in the 2014 study, the lower ATWACC reduces the annual CONE value by 3.7% for CTs and 3.8% CCs.

We present in this report and the CONE study two versions of the updated 2022/23 CONE values due to the uncertainty as to whether major maintenance costs will be allowed to be included in variable O&M costs, pending an ongoing stakeholder process.[26] This report focuses on the CONE and E&AS values with these costs in the variable O&M for comparability to prior studies and parameter values (and the possibility that PJM will change its Cost Development Guidelines back to be consistent with those). Classifying these costs as fixed instead of variable increases CONE by $19,000/MW-year for CTs (a 19% increase) and $10,000/MW-year for CCs (a 9% increase). Removing these costs from variable O&M will increase Net E&AS revenues and offset some (or all) of the increased CONE value in the calculation of Net CONE.

B. Net E&AS Revenue Offset

PJM calculates the Net CONE by subtracting the net energy and ancillary service (E&AS) revenues from the Gross CONE; net E&AS revenues are calculated using historical prices and the Peak-Hour Dispatch method, as defined in PJM's tariff (the calculation for CCs uses a modified version of the Peak-Hour Dispatch).[27] We assessed whether this E&AS methodology provides a reasonable estimate of the net E&AS revenues developers expect when constructing their reservation prices for participating in PJM's Base Residual Auctions.

Our conclusions are that the tariff-mandated Peak-Hour Dispatch method for estimating CCs' historical net E&AS revenues is validated by comparison to the actual net revenues earned by representative units.[28] For CTs, there are too few representative existing resources to make a meaningful comparison, but PJM's approach and assumptions are reasonable. However, we have identified several refinements to more accurately reflect the variable costs and revenues of the reference units: adopting the updated reference resource characteristics (*i.e.*, heat rate, capacity, variable O&M costs) estimated in the concurrently-released 2018 CONE Study; and changing the representative gas hubs for six transmission zones.

PJM can further improve its Net E&AS estimates for CCs by adopting a forward-looking approach that accounts for expected changes in market conditions and reduces the volatility of

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26 See: http://www.pjm.com/committees-and-groups/committees/mic.aspx

27 See PJM Tariff, Attachment DD.5.10(a)(v), PJM (2017h) for a description of PJM's Peak-Hour Dispatch method for a CT. For the CC, we use a modified version of the peak-hour dispatch as described in DD.5.14(h)(3)(ii).

28 The IMM provided the net energy revenues for representative plants based on its estimate of total energy and make-whole revenues minus fuel, variable operations and maintenance, and other costs.

historical simulations. Our analysis shows that CC energy margins can be closely approximated by assuming a simple dispatch against futures prices. This approach would allow PJM to use the observable market-based futures prices that developers rely on for their own forecasts to set the Net E&AS revenue offset. While futures are not liquid three years forward and do not cover all of the locations in PJM, we identified market data that PJM can use as proxies for extending the price forward and to all of the PJM transmission zones. We considered a similar approach for CTs, but have not identified any good proxies that are comparable to CCs using futures prices.

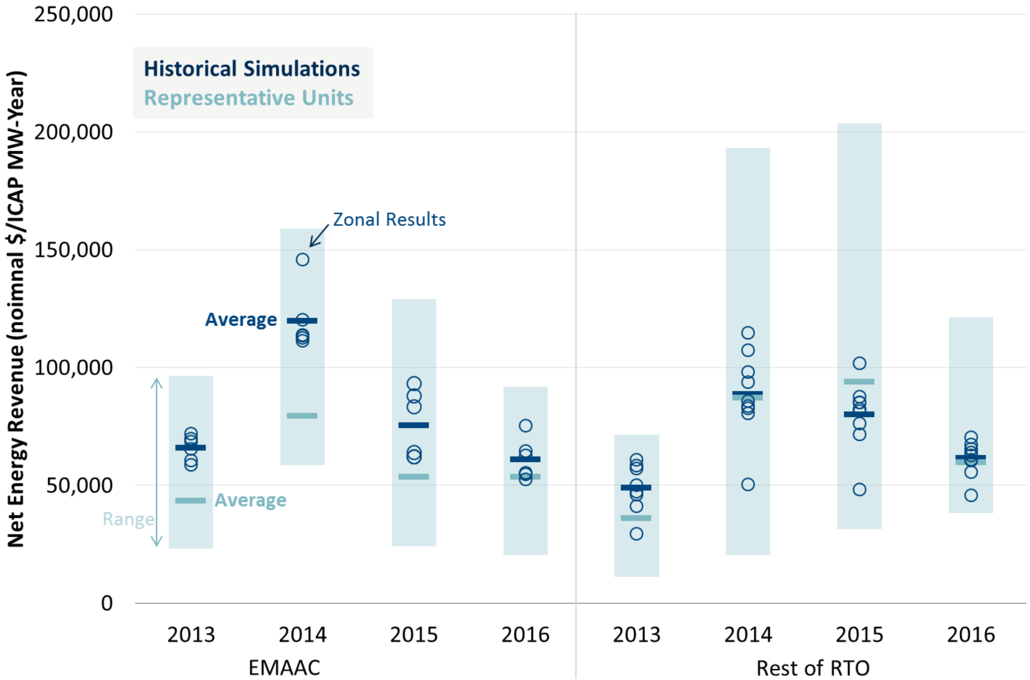
1. PJM's Peak-Hour Dispatch Against Historical Prices

We attempted to assess the accuracy of PJM's approach by comparing PJM's historical simulation results to actual historical revenues of representative plants that are similar to the reference resources. For CCs, there are numerous representative plants with comparable heat rate and unit size. For CTs, we did not identify any representative existing plants because there are limited recent new CTs and most of the existing CTs are not equipped with selective catalytic reduction (SCRs), and so must accept strict federally-enforced run limits within their Title IV air permits. These run limits inhibit the ability of the CTs from operating as often as the reference CT specified in the CONE study, especially during recent periods of low gas prices.

In Figure 2 below, we compare net energy revenues of existing representative CCs in 2013 through 2016 to the results of PJM's historical simulations in each CONE Area. The average CC net energy revenues from PJM's historical simulations are shown by the dark blue bar with the net energy revenues of each transmission zone within the CONE Area shown with the blue circles. The teal bar is the average net energy revenues of representative plants in each CONE Area with the range of revenues for representative plants shown as the shaded teal region to avoid providing market sensitive data for individual units.

PJM's historical simulations of CC net energy revenues (blue circles) fall within the range of representative units' actual net energy revenues (shaded teal region) in most cases. Simulated revenues are similar in the Rest of RTO Area and slightly higher than actual revenues in EMAAC. However, simulated net revenues are significantly higher than actual revenues in WMAAC. PJM should investigate what is causing the difference between the simulated results and the energy margins of representative CCs in WMAAC.

Figure 2
CC Net Energy Revenues



Sources and Notes:
Historical simulations provided by PJM. Representative unit net revenues provided by IMM.
There were no representative CC units in SWMAAC during this time period and too few representative CC units in WMAAC to avoid releasing market-sensitive information.

Although the historical CC estimates are reasonably consistent with representative units, we recommend that PJM consider the following changes to its simulations to accurately capture future net energy revenues and that PJM add an estimate of payments a new unit can expect under the Capacity Performance market design.

Update Reference Resource Operating Characteristics and Costs: Table 2 below displays the current operating characteristics and costs specified in the PJM tariff for the reference CT and CC and the recommended values for each input assumption based on the updated CONE study. We provide in the top half of the table the CONE values for the case in which major maintenance costs are included in the variable O&M costs, per historical treatment.[29] We then provide assumptions for the case in which these costs are included in variable O&M, which currently is

[29] For the CT, we specify major maintenance costs on a per-start basis in the case in which these costs can be included in variable O&M. We understand that PJM Cost Development Guidelines historically required these starts-based maintenance costs to be included in energy offers on a per-MWh basis. PJM can include these costs to the variable O&M assumption in their historical simulations by assuming an average runtime per start.

not allowed for cost-based energy offers but may change as the result of an ongoing stakeholder process.[30]

The updated heat rates reflect the more efficient H-class turbines recommended in the CONE study and will increase net energy revenues in PJM's historical simulations. The recommended variable O&M costs for both cases are significantly lower than the current assumptions that were specified in the Tariff in 2008. Over the past ten years, variable O&M costs have declined due to the economies of scale of the larger turbines and the increased duration between maintenance intervals recommended by the manufacturers. The lower variable O&M costs will also increase net energy revenues.[31]

Table 2
Historical Simulation Reference Resource Assumptions
(under two alternative treatments of major maintenance costs)

		CT		CC	
		Current	Updated	Current	Updated
Major Maintenance in Variable O&M, per historical treatment					
Net Heat Rate	*Btu/kWh, HHV*	10,096	9,134	6,722	6,269
Net Heat Rate with Duct Firing	*Btu/kWh, HHV*	-	-	-	6,501
Total Variable O&M	*$/MWh*	$6.47	$7.00	$3.23	$2.11
Major Maintenance in Fixed O&M and CONE, consistent with PJM's current cost guidelines					
Total Variable O&M	*$/MWh*	$6.47	$1.10	$3.23	$0.67

Source and notes:
Current values specified in PJM Interconnection, L.L.C. (2015), Open Access Transmission Tariff, effective date 4/1/2015, accessed 2/7/2018, Section 5.10 a., 5.14 h.
Net Heat Rate is estimated at ISO conditions of 59°F, 60% Relative Humidity, and at mean sea level consistent with the value in the tariff.
CT Updated Total Variable O&M of $7.00/MWh includes $5.90/MWh of major maintenance costs assuming $23,464/start from the CONE study, 11.1 hours per start (based on results of the tariff-mandated simulation), and average capacity of 358 MW across CONE Areas.

Update Natural Gas Price Hubs: The increase in natural gas production in the Marcellus formation since 2014 has shifted gas flows across the PJM region and altered pricing dynamics in

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30 There is an ongoing process underway in the Markets Implementation Committee concerning the cost guidelines for CTs and CCs. Currently, these costs are not allowed to be included in cost-based energy offers. If the guidelines do allow the costs to be included in the future, PJM should analyze whether suppliers include these costs in their price-based offers or not. If PJM determines that their offers do include these costs then PJM should adopt the costs and associated CONE values with major maintenance and overhaul costs in the variable O&M.

31 We also recommend updates to the startup cost assumptions for the updated reference resources in PJM's historical simulations, which are included in Appendix B of the CONE study.

ways that were not present when PJM last updated the representative gas hubs. We reviewed the assumed hubs used in the historical simulation for setting the gas prices in each zone and recommend that PJM consider updating the reference gas hub for six zones, as shown in Table 3.

In reviewing the relevant gas hubs for each zone, we preferred to rely on gas hubs with greater trading volumes (*e.g.*, Transco Leidy Line instead of Dominion North for PENELEC), considered constraints on the Columbia Appalachia system that have led to price disparity between Columbia Gas Appalachia TCO Pool and other Appalachian pricing hubs (*e.g.*, Dominion South instead of Columbia-App/TCO Pool for APS), and reviewed the reference gas hubs used by Platts and Energy Velocity for each zone (*e.g.*, Transco-Zone 5 Delivered instead of Transco Zone 6 non-NY for PEPCO). In addition, PJM should consider calculating the gas price for PSEG as an average of the Transco Zone 6 NY and Non-NY prices to provide a representative gas price for the entire zone, which stretches from northern New Jersey (where the Transco Zn 6 NY price is more relevant) to southern New Jersey (where the non-NY price is more relevant).

We also reviewed the gas transportation adders that PJM uses to calculate delivered gas prices, which range from $0.00 to $0.10/MMBtu in most zones and $0.15 to $0.20/MMBtu in COMED. Due to the access to interstate pipelines throughout the PJM footprint and the assumed cost of a gas lateral in the CONE study, we recommend that PJM consider eliminating the use of all transportation adders.

Table 3
Recommended Changes to Historical Simulation Representative Gas Hubs

Zone	Current PJM Reference Gas Hubs	Brattle Recommendations	Reason for Change
APS	Columbia-APP/TCO Pool	Dominion South	Constraints on the Columbia Appalachia System
DUQ	Columbia-APP/TCO Pool	Dominion South	Constraints on the Columbia Appalachia System
PENELEC	Dominion-NORTH	Transco Leidy Line	Limited liquidity of Dominion North
PEPCO	Transco-Z6 (non-NY)	Transco-Z5 Dlv	Relevant hub identified by Platts and EV
PPL	TETCO M3	Transco Leidy Line	Relevant hub identified by Platts and EV
PSEG	Transco-Z6 (NY)	Blend (see notes)	Zone-wide representative price

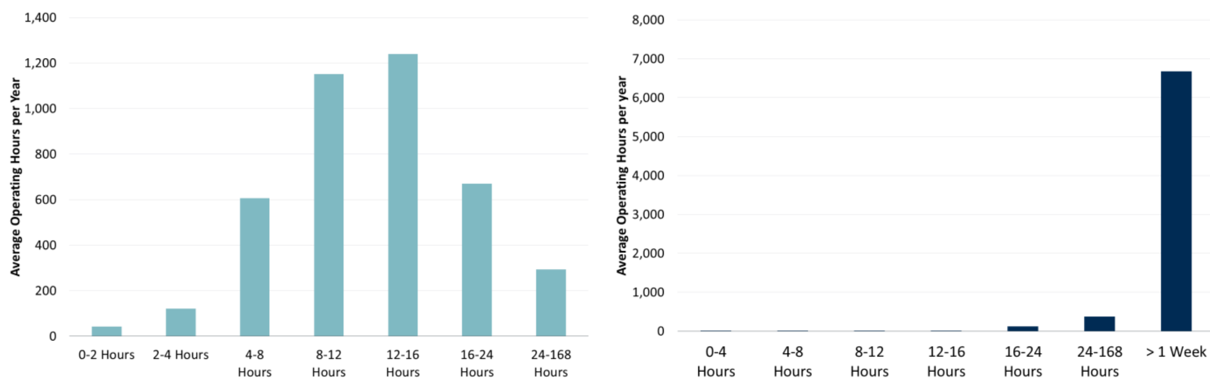
Sources and Notes:
The recommendation for PSEG is a 50%-50% blend of Transco-Z6 (NY) and Transco-Z6 (non-NY) prices.
EV data downloaded from ABB Inc.'s Energy Velocity Suite and Platts data downloaded from S&P Global Market Intelligence between August and December 2017.

Consider Including a Gas Balancing Cost Adder for CTs: 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.[32]

Maintain Current Dispatch Flexibility: The IMM models historical net energy revenues for the State of the Market report assuming more flexible operational constraints than PJM's simulations.[33] We reviewed operations of representative CTs and CCs over the past two years and our analysis in Figure 3 shows that CTs primarily operated for periods of four to twenty-four hours and CCs primarily operated for longer than a week at a time. The actual operations of these units demonstrate that the level of flexibility assumed in PJM's simulation for CTs is reasonable. Dispatching CCs during just the peak 16-hour block within each day though may limit the run time of these units and underestimate net energy revenues.

Figure 3
Historical Operational Periods of Representative Existing Units

(a) Combustion Turbine (b) Combined Cycle



Source and Notes:
Based on CEMS data for January 2016-September 2017.
CT units include Ladysmith 3-4, Marsh Run Generation 1-3 and Perryman 6.
CC units include Fremont Energy Center, Warren Power Generating, West Deptford, Newark Energy Center, and Brunswick County.

We recommend that PJM work with the IMM to investigate further whether including off-peak hours in its simulations will improve its ability to estimate the actual revenues of representative CCs and whether additional inputs that tend to overstate the net revenues in the simulations should be reconsidered.

Include Capacity Performance Payments in E&AS Revenue Offset: PJM currently does not include Capacity Performance bonus payments or non-performance charges in its estimate of the

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32 See PJM (2009f).

33 The IMM assumes the CTs can dispatch for one hour blocks and CCs for four hours blocks. PJM's simulations assume four hour blocks for CTs and sixteen hour blocks for CCs.

E&AS revenue offset. Based on the approximately 10 scarcity performance hours implied in recent BRA offers,[34] our analysis shows that a new CT and CC would receive on average about $2,000/MW-year in net performance payments.[35] We recommend that PJM include an estimate of the performance payments (or potential charges) when setting future Net E&AS revenue offsets. PJM could calculate the performance payments based on recent historical payments to representative units, similar to the energy margins, or use an approach similar to the calculation above if PJM's adopts a forward-looking estimate of energy margins.

2. Option for a Forward-Looking E&AS Offset Approach

PJM should consider estimating the Net E&AS revenue offset using a forward-looking approach that will provide a better representation of developer's expectations for net energy revenues. We recommend that PJM adopt a forward-looking approach for CCs because CC net energy revenues can be reasonably approximated during on-peak hours. This allows the use of observable futures prices to estimate net energy revenues. While the futures at the most-heavily traded hub in PJM, Western Hub, are not liquid beyond a year or two forward, we developed an approach that utilizes the best available market data to project future net E&AS revenues. However, this approach does not work well for CTs, because their dispatch does not closely match any observable forward-traded product. We did not identify an alternative for CTs that is superior to the historical approach.

Using historical 2009–2016 peak hours prices, we tested whether a simple, blocky dispatch (which we refer to as the "Simple Dispatch" below) can closely approximate the energy margins calculated using PJM's more granular historical simulations. Figure 4 below shows the monthly net energy revenues for the reference CC in the APS zone for 2009 to 2016 for PJM's granular Peak-Hour Dispatch (purple line) and the Simple Dispatch (red line). The monthly trends in energy margins of the two approaches are similar with the Peak-Hour Dispatch higher than the Simple Dispatch in most months because the more granular dispatch avoids uneconomic dispatch blocks.[36] On average over the eight year period, PJM's Peak Hour Dispatch revenues are 12% higher than the Simple Dispatch. Performing a similar analysis for each zone results in Simple Dispatch net energy revenues that are 6–18% lower (12% on average) than PJM's more granular approach, as shown in Figure 5.

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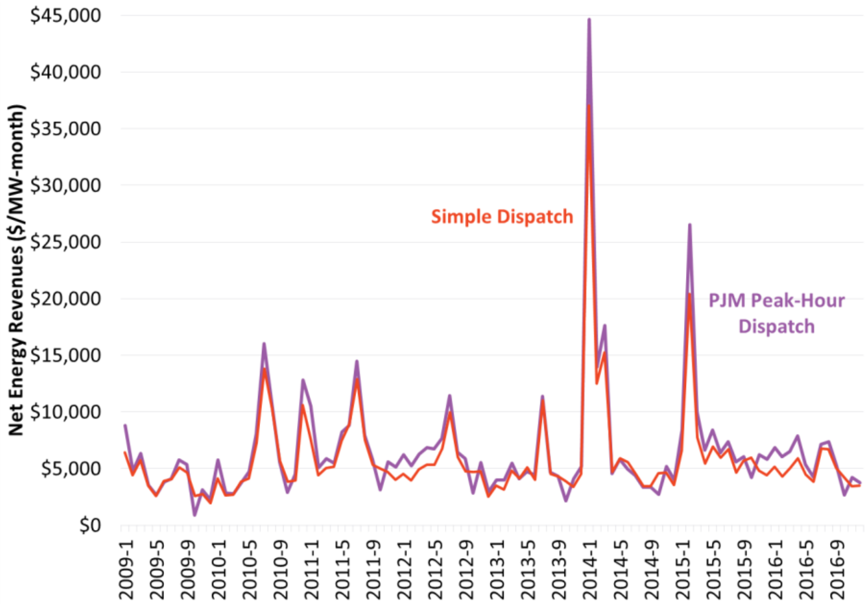
34 See Appendix B for an explanation of expected performance hours implied by recent offers into the BRA.

35 The performance payment calculations assume a penalty rate of $1,500/MWh (assuming Net CONE of $122/MW-day), a balancing ratio of 78.5%, and resource availability of 90.2% for the CT and 95.3% for the CC based on the average EFORd for each resource type.

36 PJM's Peak-Hour Dispatch assumes a two-week outage in October resulting in lower energy margins than the Simple Dispatch in each year simulated.

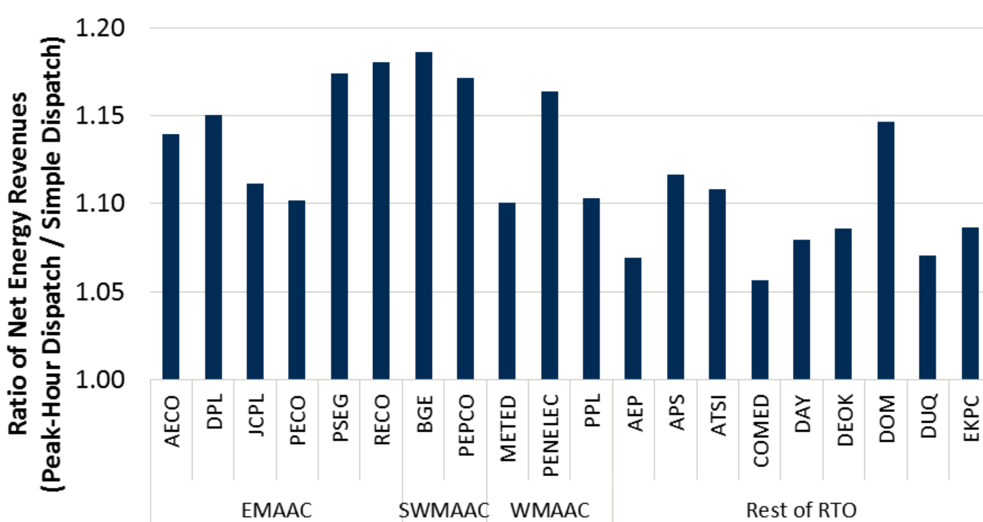
Figure 4
Comparison of Simple Dispatch and Historical Simulation Results in APS



Sources and Notes:
Historical simulations provided by PJM.

This analysis shows that dispatching the reference CC against 5×16 futures prices results in a reasonable approximation of net energy revenues from PJM's historical peak-hour dispatch. We can account for the underestimation of the Simple Dispatch against peak hour prices by grossing up the net energy revenues based on the results of the historical (2009 – 2016) analysis for each zone (i.e., gross up the Simple Dispatch net energy revenues for BGE by 18% and for PPL by 10%).

Figure 5
Ratio of Peak-Hour Dispatch to Simple Dispatch Net Energy Revenues



The PJM Western Hub electricity futures are the most liquid in PJM, but there is limited trading volume on contracts three years forward and do not reflect prices across the PJM market.[37] However, our analysis shows that the reported 2021/22 Western Hub on-peak prices reflect the trends in gas prices and near-term market heat rates. (Note that we estimate 2021/22 electricity prices and CC E&AS margins using the forward-looking approach to compare to the 2015-2017 historical simulations used for the upcoming 2021/22 BRA.) For this reason, we find that they are a significant improvement to using historical gas and electricity prices for estimating the net energy revenues for new CCs three-years forward.[38] The 2021/22 Western Hub on-peak prices can also be extended to each of the PJM transmission zones by using the most recent long-term Financial Transmission Rights (FTR) auction results.[39] We developed zone-specific on-peak electricity prices by starting with the Western Hub futures prices and applying the annual congestion between Western Hub and each transmission zone implied by the long-term on-peak FTR auction results. The monthly electricity prices can then be shaped based on the historical average electricity prices in each zone and adjusted for historical differences in losses between Western Hub and each zone.

Figure 6 shows the projected monthly electricity prices for one zone in each CONE Area through the 2021/22 commitment period. The projected prices continue to peak in the winter, especially in the MAAC Areas, and trend slightly downward with 2021/22 prices on average about 7% lower than 2015-17 peak prices. Prices decline more significantly in MAAC than Rest of RTO due to differences in congestion implied by long-term FTRs; BGE prices are 16% lower than recent historical prices, while COMED prices (not shown) are just 2.5% lower.

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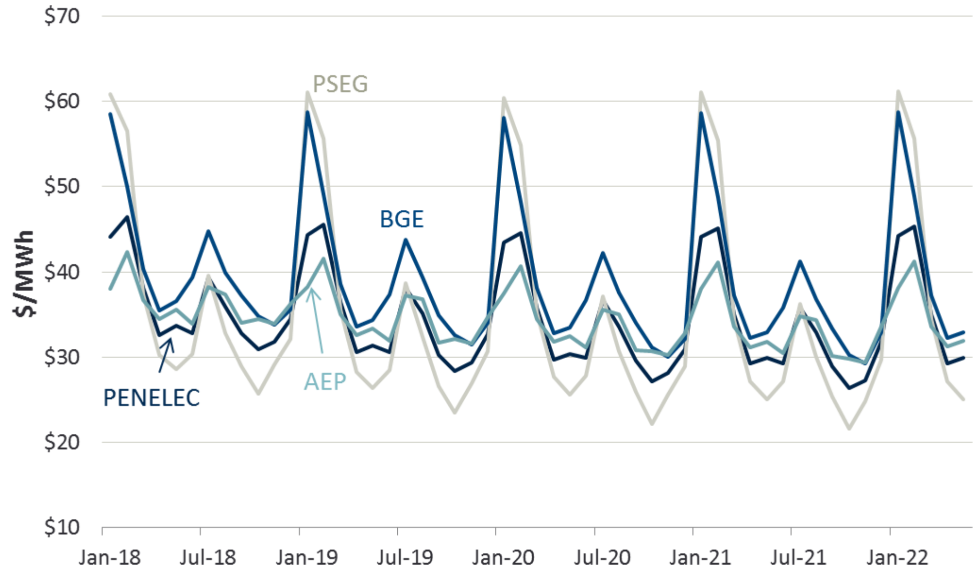
37 The Open Interest on PJM Western Hub futures contracts steadily declines from nearly 6,000 per month over the next year to zero in 2022.

38 We developed a fundamentals-based projection of Western Hub prices using the best available market data: the long-term Henry Hub gas futures (which have open interest out to 2022); the near-term basis differentials between Henry Hub and Dominion South futures (the gas hub with the most liquidity in PJM's footprint); and, the near-term market heat rates implied by Dominion South and Western Hub. We used these components to project Western Hub prices in 2021/22 by starting with the long-term Henry Hub gas prices, adding the near-term monthly Dominion South basis differentials (assuming basis differentials remain constant in real dollars), and finally multiplying the resulting gas prices by the near-term monthly market heat rates. The projected Western Hub prices closely align with the current long-term Western Hub prices.

39 The long-term FTR auctions conducted in 2017 included FTRs out to 2020/21. For projecting the values forward to 2021/22, we assume FTRs will scale with Western Hub prices. PJM posts FTR auction results here: http://www.pjm.com/markets-and-operations/ftr.aspx

Figure 6
Estimated Electricity Prices, 2018 to 2023

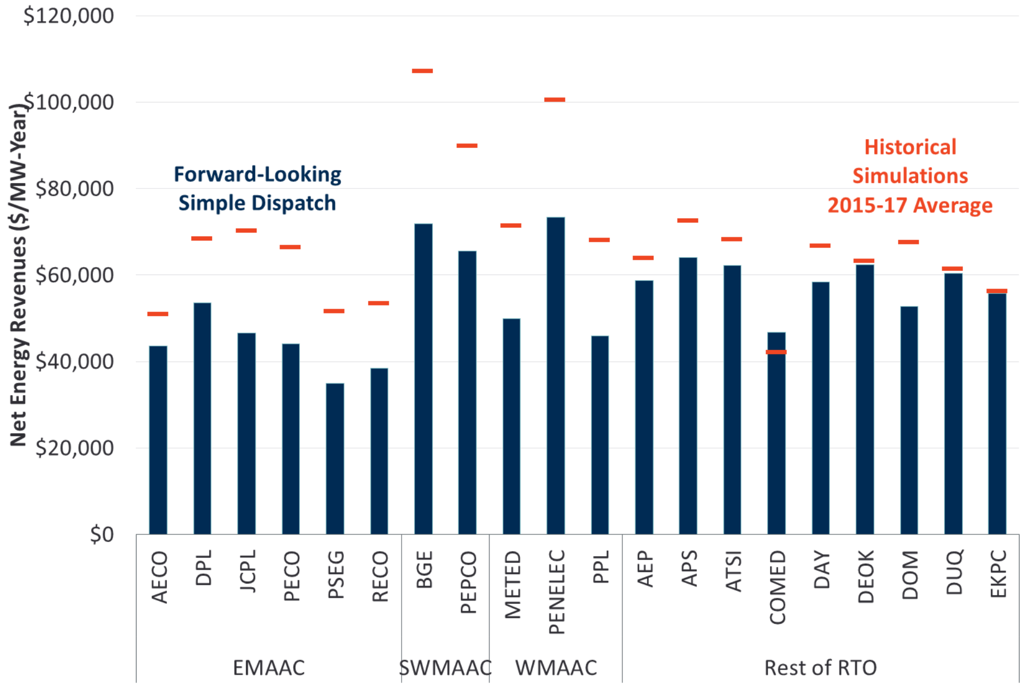


To estimate 2021/22 net energy revenues for a CC in each transmission zone, we dispatched the reference CC using the projected 2021/22 zonal on-peak prices described above and operating costs based on the current assumptions in PJM's historical simulations for operating characteristics (see Table 2 above) and representative gas price hubs.[40] To account for the historical underestimation of energy revenues using the Simple Dispatch, we grossed up the estimated 2021/22 energy margins by the zone-specific adjustment factor shown in Figure 5.

Figure 7 shows a comparison of the CC 2015-17 average net energy revenues from PJM's historical simulations (red dashes) to the forward-looking 2021/22 net energy revenues (dark blue bars). The forward-looking 2021/22 net energy revenues are lower than the historical simulations by 29% on average across the MAAC zones ($21,000/MW-year lower) and 7% lower in the Rest of RTO zones ($4,500/MW-year lower). These 2021/22 net energy revenues are explained by the differences in electricity and gas prices between the recent historical period and 2021/22. The lower energy margins in 2021/22 reflect declining electricity prices across all zones, but especially MAAC zones as described above. In addition, gas prices are trending higher in MAAC (Transco Zone 6 non-NY prices increase by 13% over the next three years), while Columbia Appalachia prices in the western portion of the market are expected to decrease slightly by 3%.

40 We projected 2021/22 gas prices by adding the basis differential over the next 12 months between the relevant hub prices and Henry Hub prices (constant in real terms) to the 2021/22 Henry Hub prices.

Figure 7
Historical 2015-17 Average and Forward-Looking 2021/22 CC Net Energy Revenues
Assuming current CC reference technology specifications for comparison purposes



The forward-looking E&AS margins increase when the lower heat rate and variable O&M associated with the updated CC reference technology (see Table 2 above) and updated gas hubs are included in the simple dispatch. The increase in the E&AS margins from the values shown above in Figure 7 range from $7,500/MW-year in PEPCO to $28,500/MW-year in PPL.

If PJM chooses to implement the forward-looking approach for CCs, PJM will need to update the Simple Dispatch with the most recent gas and electricity futures prior to each auction and apply the adjustment factors in Figure 5 to re-calculate the net energy revenue offset.

C. Indicative Net CONE Estimates

We present in Table 4 indicative CT and CC Net CONE estimates for all the LDAs compared to the parameters PJM used in its most recent BRA (for 2021/22 delivery). We say "indicative" because the scope of our assignment includes estimating Gross CONE values, which does not require estimating E&AS offsets. The indicative E&AS estimates shown for CTs are based on simulations provided by PJM staff, using historical prices from 2015 through 2017. These estimates do not account for any of our recommended refinements and continue to treat major maintenance costs as a variable cost. The values shown for CCs are based on our application of the forward-looking approach we recommend for CCs; they account for the 6,300 Btu/kWh heat rate of the new CC technology.

We generally find that since the last update the Net CONE values in the Rest of RTO CONE Area decreased more than the MAAC LDAs. This is primarily due to increased net E&AS revenues in these portions of the PJM system.

Table 4
CC and CT Net CONE Estimates by Location (Nominal Dollars)

All values in $/MW-day UCAP	2021/22 BRA CT	2022/23 Brattle Estimate CT	2022/23 Brattle Estimate CC
CONE Area 1			
AECO	$330	$250	$164
DPL	$300	$221	$135
JCPL	$294	$214	$156
PECO	$300	$220	$164
PSEG	$331	$251	$187
RECO	$328	$248	$177
EMAAC	**$314**	**$234**	**$164**
CONE Area 2			
BGE	$244	$145	$92
PEPCO	$285	$187	$125
SWMAAC	**$265**	**$166**	**$108**
CONE Area 4			
METED	$292	$201	$135
PENELEC	$214	$126	$72
PPL	$301	$210	$96
MAAC	**$293**	**$207**	**$137**
CONE Area 3			
AEP	$317	$214	$107
APS	$296	$194	$72
ATSI	$307	$204	$95
COMED	$344	$240	$142
DAY	$313	$210	$107
DEOK	$313	$211	$96
DUQ	$318	$215	$84
DOM	$317	$212	$117
EKPC	$328	$225	$115
RTO	**$322**	**$222**	**$129**

Sources and Notes:
Major maintenance costs are included in VOM costs for both CONE and E&AS.
2021/22 BRA values are taken without adjustment from 2021/22 BRA parameters, PJM (2018).
E&AS for CT is consistent between 2021/22 BRA and Brattle CT estimates. Brattle estimates include Capacity Performance bonus payments.
Brattle estimates are converted from ICAP to UCAP using 2020/21 BRA EFORd of 6.59%.

D. Construction of "RTO-Wide" Net CONE for the System VRR Curve

PJM's current approach to estimating RTO Net CONE consists of two steps. First, PJM calculates the RTO Gross CONE parameter by taking the simple average of Gross CONE values across the four CONE areas. Second, PJM estimates net E&AS revenues by running its dispatch model for a hypothetical unit purchasing gas at an appropriate pricing point and earning the average LMP across the footprint. While PJM's approach to calculating RTO Gross CONE is reasonable, we recommend that PJM modify its calculation of RTO net E&AS revenues and estimate this parameter as the median of net E&AS revenues across LDAs. Similarly, we recommend that PJM estimate net E&AS revenues for each multi-zone LDA (e.g., MAAC, EMAAC) as the median of net E&AS revenues across LDAs within the multi-zone LDA.

The major drawback of PJM's current approach to estimating RTO E&AS margins is that it uses gas and electricity prices that are not consistent with each other and thus might express false price spreads. E&AS margins estimated using these prices are not earned by any actual resource and might be higher or lower than a representative LDA. For all auctions since 2018/19, RTO E&AS offsets have been 18-26% lower than the average E&AS margin across zones, and 7-20% lower than the median E&AS margin. Under current market conditions, it therefore appears that PJM's current approach may underestimate E&AS margins. However, under other market conditions, the approach could over-estimate E&AS margins, leading to under-procurement and reliability challenges.

There are several advantages to using the median instead of the average LDA value to set the RTO E&AS parameter. First, this approach should yield an approximately efficient result under equilibrium conditions. Under equilibrium conditions, import-constrained LDAs will have higher Net CONE than their parents, and will likely have lower E&AS margins. The median E&AS margin will not be affected by a small number of LDAs with very low E&AS margins, and will therefore contribute to providing the right incentive for investment in the unconstrained portion of the system.

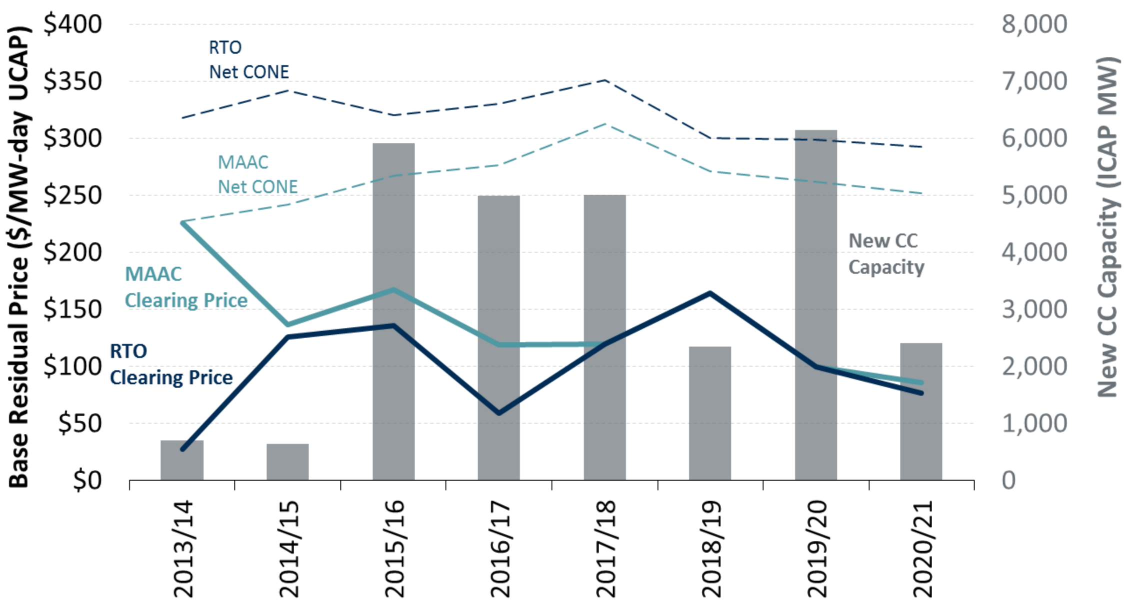
Second, the median should be relatively robust under conditions that deviate from equilibrium. Under conditions where some LDAs have abnormally high E&AS values in the short-run, the median value will not be affected. This will keep Net CONE high enough to support investment in the rest of the footprint. The median approach also provides a measure of protection from administrative error in estimating E&AS margins that may occur in some LDAs due to the small sample of units to choose from or the difficulty of fully capturing locational varying costs and energy prices. Using the median value prevents RTO Net CONE from being unduly influenced by such errors and results in a more stable estimate over time.

E. CHOICE OF REFERENCE TECHNOLOGY

PJM currently uses a CT as the reference technology for the VRR curve. However, we recommend that PJM consider changing to the CC as the reference technology to align the VRR curve with observed entry and avoid unnecessary costs while continuing to meet reliability objectives. Section IV.D below evaluates the cost and reliability implications of doing so. The present section discusses the basic attributes of CCs and CTs affecting their suitability as reference technologies.

Our cost study indicates that CCs are currently more economic than CTs. The updated CC Net CONE is 25–63% below the CT Net CONE across the PJM transmission zones. Recent entry is consistent with this result: nearly 27,000 MW (ICAP) of new CC generation has cleared in the past several BRAs, with prices ranging from 50–80% below administrative estimates of Net CONE for a CT, as shown in Figure 8, while little new combustion turbine generation has cleared in the same period.[41] With PJM's current VRR curve, the low prices of recent auctions correspond to supply in excess of the requirement. Section IV.D shows that a VRR curve based on higher-net-cost CTs as the reference technology will perpetuate this excess capacity in the long run, at a cost to customers.

Figure 8
Historical BRA Capacity Prices and New CC Capacity



Sources and Notes:
PJM Base Residual Auction Reports and Planning Parameters. See PJM BRA results 2007/08–2020/21.

41 Based on RTO clearing prices and Net CONE parameters. See Table 8, PJM (2017d)

Another consideration is the ability to estimate Net CONE accurately. The conventional wisdom has always been 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. As we showed above, CCs' net E&AS revenues can be accurately approximated based on 5x16 operation, and futures prices for 5x16 on-peak blocks are observable in the market. No such benchmark is available for CTs, 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, as discussed in Section II.B above.

A separate issue from forecast error is volatility. In theory, CC E&AS offsets and Net CONE values vary more than they do for CTs as market conditions fluctuate. This could potentially increase capacity price volatility and adversely affect capacity resources, such as demand response, that do not earn meaningful net energy revenues. However, forward-looking E&AS offsets for CCs avoid the volatility seen in historically-based E&AS offsets for CTs when anomalies such as the Polar Vortex occur. Such anomalies are presumed to be implicitly included in futures prices with appropriate weightings on their future probability, as determined by the market. Indeed, the use of forward-looking E&AS offsets for CCs could reduce volatility relative to historical offsets used for CTs.

We and other analysts have long cautioned against repeatedly switching to the current lowest cost reference technology in a market where Net CONE for each resource type may fluctuate from year to year around its long-run equilibrium value. This practice would suppress long-run average administrative Net CONE below long-run average actual Net CONE, resulting in VRR curve prices too low to sustain investment consistent with target reserve margins. We believe, however, that the cost advantage of CCs reflects fundamental long-term cost drivers, rather than a temporary deviation from equilibrium. CCs have been the dominant technology for many years. While this was also the case during the previous VRR curve review in 2014, an additional four BRAs with even greater CC entry and limited CT entry has further emphasized the shift in the market. Going forward, their substantial heat rate advantage relative to CTs should overcome their slightly higher Gross CONE on a per-kW basis. The convergence of the Gross CONE between the two resource types since the 2014 review means that CCs are likely to remain more cost effective under wide ranging market conditions. It is conceivable that CTs could become economic in a high-renewable future where their flexibility is more highly valued and the energy value of CCs is lower.[42] However, it is unlikely that CTs will become strictly

42 In our 2014 Review, we stated that any technology that is economically viable in the long run could be selected for determining Net CONE. We continue to believe this. However, given the tremendous net cost advantage of CCs and recent new entry evidence in the market, it is not clear that CTs will remain part of the supply mix in equilibrium.

more economic over several auctions and that PJM (or intervenors) will then be tempted to switch back the reference technology.

We understand that ISO-NE recently switched its reference technology from a CC to a CT after they estimated that CT Net CONE was 20% below CC Net CONE in New England, its auction cleared a frame-type CT, and they passed market reforms that favor fast-start and flexible resources. The FERC accepted ISO-NE's request on the basis that Net CONE for the lowest cost commercially available resource is high enough to incentivize new entry, but not so high that customers incur unnecessary costs. In contrast to ISO-NE's findings in New England, our CONE study suggests that CCs are less expensive than CTs in PJM, and CCs are the strongly dominant technology of actual entrants. Our recommendation that PJM adopt a CC as the reference technology aims to achieve the same outcomes that the FERC approved for New England: attracting new entry without driving up customer costs unnecessarily.[43]

[43] ISO New England, Inc., (2017). "RE: ISO New England Inc.; Filing of CONE and ORTP Updates," January 13, 2017. Docket No. ER17-795-000.

III. Probabilistic Simulation Approach

The position, slope, and shape of PJM's VRR curve have consequences for realized reliability levels and price volatility in the capacity market. The parameters of the VRR curve determine the expected distribution of price and quantity outcomes, but these effects are not observable in historical market outcomes with only a few years of historical experience. We therefore use a Monte Carlo model to simulate distributions of price, quantity, and reliability outcomes that might be realized over many years under PJM's current VRR curve or alternative curves. We describe here the primary components of this model, including our characterization of supply, demand, transmission, reliability, and locational auction clearing. We describe how we enhance our approach to account for the substantial impact of Capacity Performance on the shape of the RPM supply curve and how it affects our modeling.

A. Model Structure

To evaluate the performance of the VRR curve and alternative curves in long-run equilibrium, we conduct a Monte Carlo simulation of capacity market outcomes. 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.

The Monte Carlo simulation model we employ in this analysis is an enhanced version of the model used in our 2014 VRR curve report.[44] We originally developed the model to represent the characteristics of PJM's RPM. We calibrate the size and standard deviations of fluctuations in supply and demand, at the RTO level and within each LDA, to levels observed historically in PJM. The model uses a realistic sloped supply curve that is calibrated based on RPM offers and reflects the wide range of capacity resources bidding into the market. The model realistically accounts for the impact of Capacity Performance on the supply curve. It captures the range of expectations of performance risk across market participants and the resulting increase in supply curve prices at the low end of the price range.

We use the planning parameters for delivery year 2020/21 as the basis for our modeling assumptions, combined with historically-grounded locational supply curves, to determine locational clearing prices and quantities. We also evaluate performance of PJM's VRR using updated Gross and Net CONE values from our concurrently released CONE study. We then use historical market data to develop realistic fluctuations to supply, demand, and transmission in each draw. A stylized depiction of the price and quantity distributions driven by supply and

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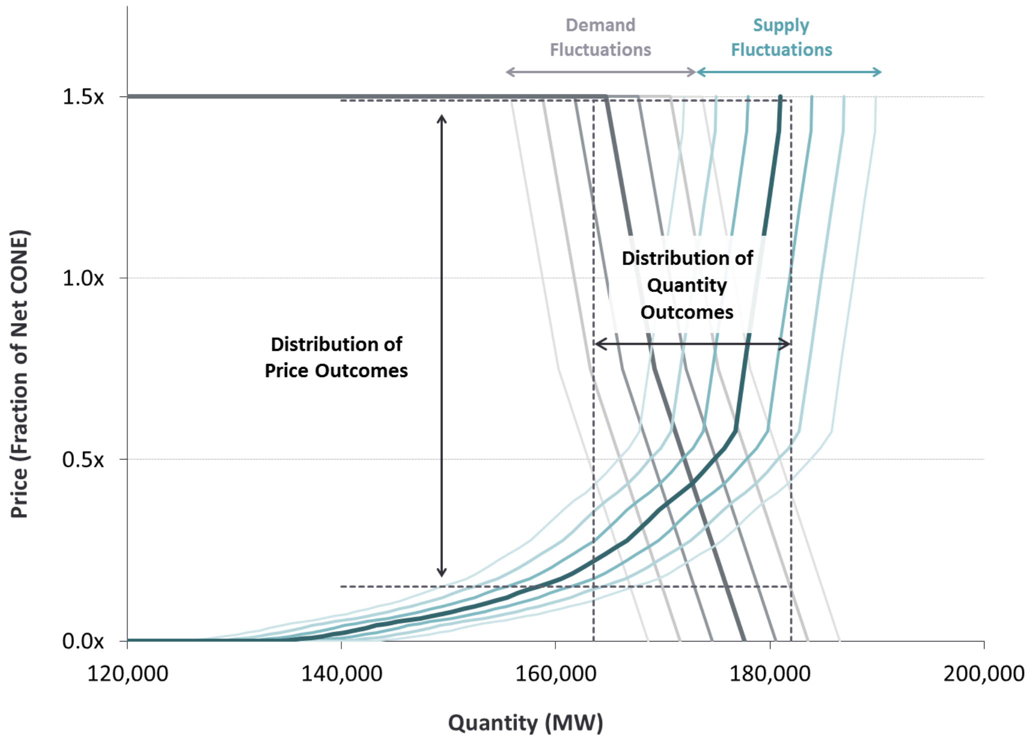
[44] A similar model was originally developed by Professor Benjamin Hobbs to evaluate VRR curve performance and we have used variants of this model to help develop and evaluate capacity market demand curves for ISO-New England (ISO-NE), the Alberta Electricity System Operator (AESO), and the Midcontinent ISO (MISO). See discussion of the Hobbs simulation model in our 2008, 2011, and 2014 RPM Reports, Pfeifenberger *et al.* (2008, 2011, and 2014).

demand fluctuations is shown in Figure 9, with the intersection of supply and demand determining price and quantity distributions. The shape of these distributions will change with the shape of the demand curve.

We assume economically rational new entry, with supply entering or exiting the market infra-marginally until the long-term average price equals Net CONE.[45] As such, our simulations reflect long-term economic equilibrium conditions on average, and do not reflect a forecast of outcomes over the next several years or any other particular year.

Figure 9
Stylized Depiction of Supply and Demand Fluctuations in the Monte Carlo Analysis



Note:
Illustrative fluctuations in supply and demand are fluctuation magnitudes modeled in the Base Case run.

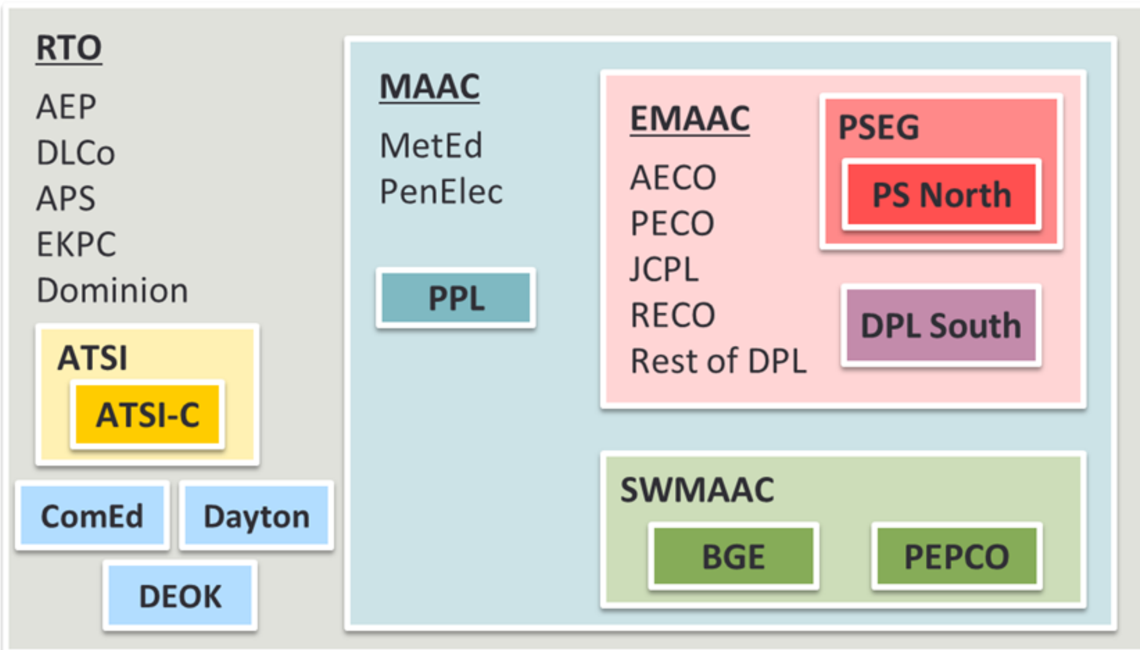
B. Demand Modeling

We include administrative demand curves at both system and local levels in a locational clearing algorithm that minimizes capacity procurement costs subject to transmission constraints. We

45 An alternative approach would have been to model new supply as a long, flat shelf on the supply curve set at Net CONE, but that would be inconsistent with the range of offers we have observed for actual new entrants, and it would artificially eliminate price volatility. Our modeling approach reflects the fact that short-run capacity supply curves are steep, resulting in structurally volatile prices, while long-run prices converge to long-run marginal costs, or Net CONE.

model zonal structure consistent with planning parameters for the 2020/21 delivery year in PJM's market, as shown schematically in Figure 10.

Figure 10
Nested Zonal Structure Consistent with 2020/21 BRA



Notes:
Each rectangle and bold label represent an LDA modeled in 2020/21 BRA; individual load zones that are not modeled in RPM auctions are not bold, see PJM (2017c).

C. Supply Modeling

In each simulation draw, we generate locational and system supply curves that are cleared against the relevant demand curves to produce price and quantity outcomes. We adjust the *total* quantity of supply until long-run average prices equal Net CONE, consistent with the effect of market forces driving merchant entry and exit decisions. We model the *shape* of the supply curve in two steps. We start by modeling a basic shape consistent with offers in pre-Capacity Performance auctions. These supply curves featured a large segment of offers at or near zero, followed by a steep hockey stick-like segment at high quantities. We then incorporate the impact of Capacity Performance, which increases prices on the lower-priced portion of the supply curve.

1. Supply Entry, Exit, and Offer Prices

The supply curve shape is a driver of volatility in cleared price and quantity in our modeling, as it is in real capacity markets. A gradually-increasing, elastic supply curve will result in relatively stable prices and quantities near the resource adequacy requirement even in the presence of fluctuations to supply and demand, while a steep supply curve will result in greater volatility. We generate supply curve shapes consistent with historical capacity auctions using offer data from PJM. We rely on offer data from years prior to the introduction of Capacity Performance (*i.e.*, through 2017/18) to generate our basic supply curve shapes and then separately model the impact of Capacity Performance on supply curve shapes.

We use historical PJM offer prices and quantities to create nine realistic supply curve shapes, consistent with the supply curve shapes from the PJM BRAs conducted over 2009/10 to 2017/18.[46] To develop comparable supply curve shapes consistent with the 2020/21 delivery year, we escalate all offer prices to the 2020/21 delivery year and normalize the quantity of each curve by the quantity of offers below a normalization price of $351/MW-day.[47] Smoothed versions of the resulting supply curve shapes are presented in Figure 11, showing a range of shapes from the steepest curve in 2013/14 to the flattest, or most elastic curve, in 2015/16, when many existing units offered at higher levels reflective of the expense of environmental retrofits.[48] However, in all years the supply curve becomes quite steep at high prices above $300/MW-day, a market fundamental that underpins the structural volatility of capacity markets in the real world as well as in our modeling.

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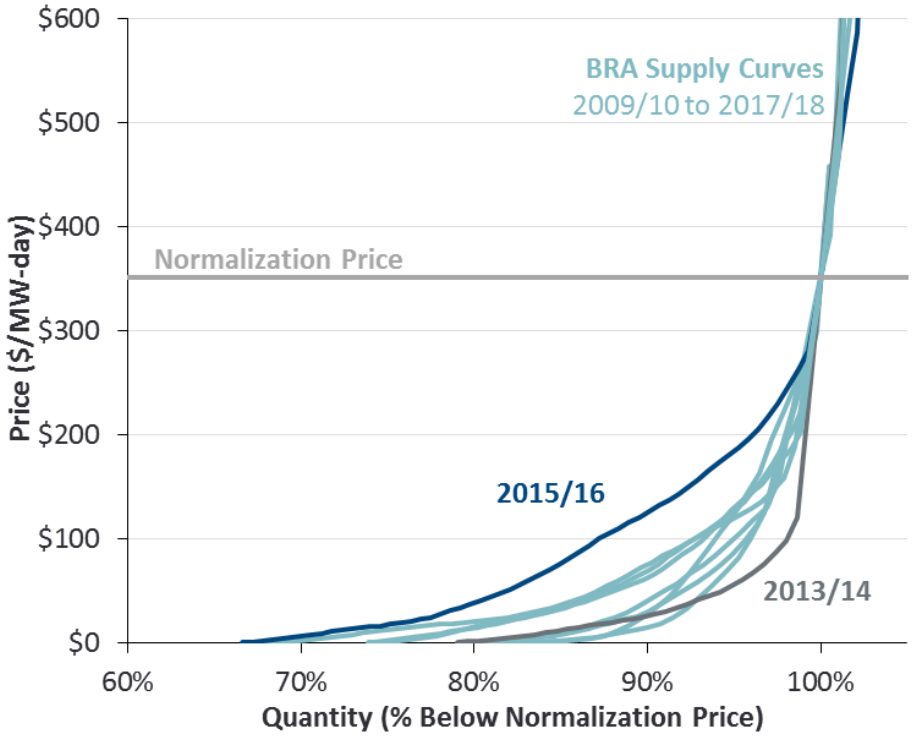
46 Developed from auction supply curve data provided by PJM staff. We exclude data from the initial two BRAs, because those auctions were conducted on a shorter forward period and therefore exhibited a steeper supply curve shape that we expect in typical BRAs. The curves reflect the aggregate resource supply curve that would be available to meet the VRR curve, and so contingent bids for different DR products are collapsed into a single offer for the maximum quantity available from each resource.

47 $351/MW-day was the Net CONE reported in the 2017/18 BRA parameters. See PJM (2014e). We use inflation factors consistent with the BLS composite index used by PJM to escalate Gross CONE.

48 Those environmental retrofits were required by the Mercury and Air Toxics Standard (MATS) which induced retire-or-retrofit decisions on a substantial portion of PJM's coal fleet beginning with the 2014/15 BRA. See additional discussion of the impacts of this rule in Section II.A.3 of Pfeifenberger (2011).

Figure 11
Individual Basic Supply Curve Shapes used in Monte Carlo Analysis



Sources and Notes:

Smoothed supply offer curves developed from raw data provided by PJM staff.
Offer curves normalized by quantities offered below $351/MW-day and inflated to 2020/21 dollars.

We reflect the lumpy nature of investments by simulating each supply curve as a collection of discrete offer blocks. Simply modeling a smooth offer curve, like one of the individual smoothed curves shown in Figure 11, would somewhat understate realized volatility in price and quantity outcomes, especially in small LDAs that are more greatly affected by lumpy investments. To derive realistically-sized offer blocks in each location, we randomly select from actual offers in that location from the 2017/18 BRA but re-price those offers consistent with the selected smooth supply curve shape.

To simulate rational economic entry, we increase or decrease the quantity of zero-priced supply so that the average clearing price over all draws is equal to Net CONE.[49] The result is that average-clearing prices will always converge to Net CONE under all possible demand curves, although differently-shaped demand curves will result in different average-cleared quantities. This approach allows us to examine the performance of the VRR curve in a long-term

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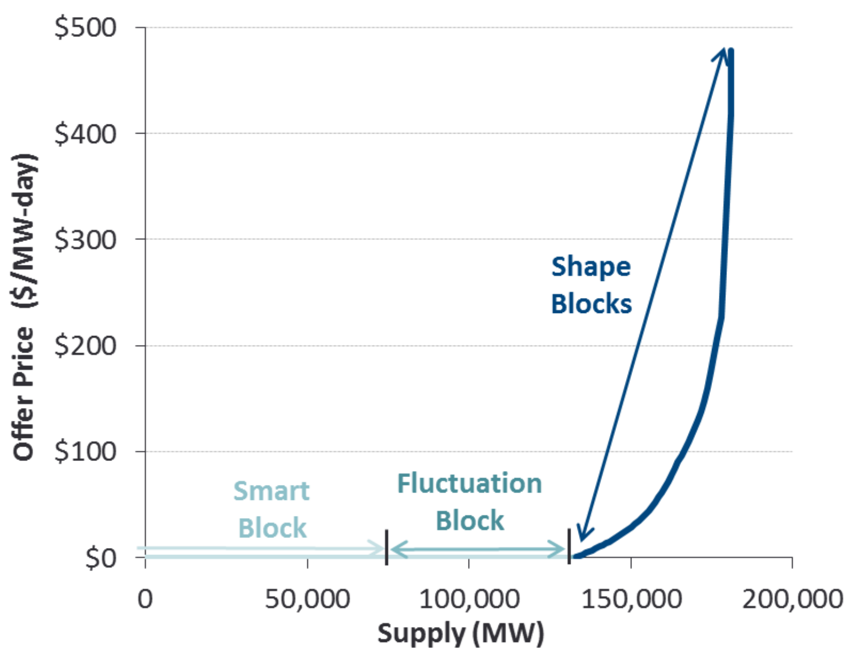
49 In the second step of our supply curve modeling, many of the zero-priced offers rise above zero, consistent with Capacity Performance offers in the 2018/19 through 2020/21 BRAs.

equilibrium state. Too much zero-priced supply would result in an average price below Net CONE, while too little supply would result in an average price above Net CONE.

We provide a stylized depiction of the components of the basic supply curve in Figure 12. The block of zero-priced supply used for normalization is shown as the "Smart Block," and is held constant across all Monte Carlo draws for a given demand curve, but is slightly different between demand curves.[50] For example, with a right-shifted demand curve, more supply would be included in the smart block. If instead the same smart block were used, then clearing prices with the right-shifted curve would be higher than with the original curve. In contrast to the smart block, the quantity of the "Fluctuation Block" varies with each draw to generate fluctuations to the supply curve, as described in Section III.D below. Finally, the "Shape Blocks" are the collection of offers at above-zero prices generated using historical BRA offer data as described above.

Figure 12
Stylized Depiction of Simulated Basic Supply Curve Components



Notes:
Smart block and fluctuation blocks both represent quantities of supply that are offered at zero-price, and are used as adjustable parameters in our model.
Shape blocks represent the supply that is offered at non-zero prices, and is based on historically observed supply as shown in Figure 11.

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50 We refer to it as the "Smart Block" because it reflects rational entry or exit from the market in response to market signals, this differs from the "Fluctuation Block", which reflects random deviations that are not driven by rational economic decision-making. We calculate the appropriate "Smart Block" in each location under each demand curve by first running a convergence algorithm over 9,000 draws to determine the quantity that will result in long-run prices equal to Net CONE; we then run a final 1,000 draws with the converged fixed smart block size and report only these draws in this report.

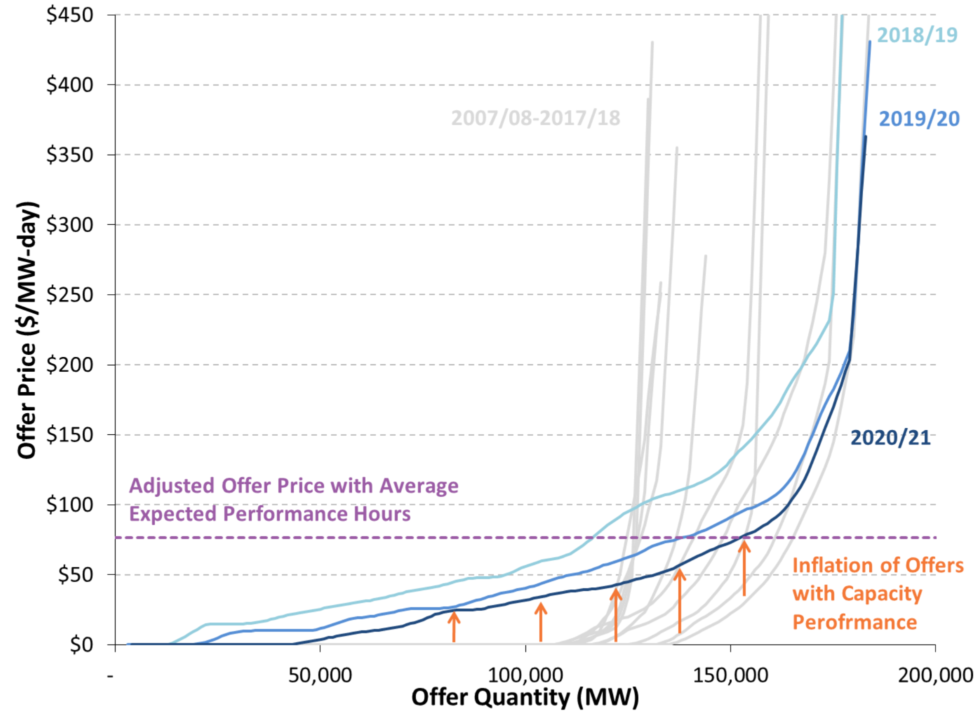
2. Supply Curve Adjustments for Capacity Performance

Following capacity shortfalls during the 2014 Polar Vortex, PJM developed the Capacity Performance construct to ensure that the RPM delivered the expected level of reliability. Capacity Performance created significantly stronger incentives for resources committed in the capacity auction to meet their obligations. It also compensated resources choosing to forego capacity obligations by providing bonus payments on their full output during performance events. Capacity Performance has significant implications for how the RPM will function going forward because of how it affects offer price incentives and reliability outcomes under a given demand curve. To enhance our modeling approach, we use a combination of economic theory and analysis of auction data to gain a detailed understanding of how offer behavior is changing with Capacity Performance.

To understand the impact of Capacity Performance on supply curves, we analyzed BRA offer data before and after Capacity Performance was implemented. The available data included offers from the non-Capacity Performance auctions (2007/08–2017/18 BRAs) and the Capacity Performance auctions (2018/19–2020/21 BRAs).[51] Figure 13 compares supply curves from the recent Capacity Performance auctions (indicated by the colored lines) to pre-Capacity Performance supply curves (grey lines) and shows how offers have changed. The Capacity Performance supply curves have fewer zero-priced offers and more offers with gradually increasing prices compared to earlier curves. Offers in the low-priced portion of the curve have increased *on average*, reflecting the opportunity cost of foregone bonus payments that will be discussed below.

[51] The first Capacity Performance auctions were conducted in 2015, when PJM held the 2018/19 BRA and two special transitional auctions to procure Capacity Performance resources for the 2016/17 and 2017/18 delivery years. In the 2018/19 and the 2019/20 BRAs, PJM procured both Capacity Performance resources (subject to a minimum quantity constraint) and "Base" resources, which were not subject to performance penalties. Resources could choose to offer as either type, with Capacity Performance resources receiving a premium above the Base price. PJM set targets of procuring Capacity Performance resources up to 60% and 70% of the reliability requirement for the 2016/17 and 2017/18 Transition Auctions, respectively. Starting with the 2020/21 BRA, PJM procured only the Capacity Performance product. See PJM (2015c).

Figure 13
Smoothed Capacity Performance and Pre-Capacity Performance Supply Curves



Sources and Notes:

Supply offer curves developed from raw data provided by PJM staff and smoothed to remove confidential resource information.

2018/19, 2019/20, and 2020/21 curves represent BRAs with Capacity Performance and other curves represent pre-Capacity Performance BRAs.

Average expected H was calculated by tracking the low-priced supply offers in the pre-Capacity Performance auctions and seeing how their offer prices increased in the Capacity Performance BRAs. Expected H ranged from 0 to 30 across all supply offers.

Capacity Performance bonuses and penalties should have an impact on supply offers into the capacity auction because there is an opportunity to earn revenue during emergency events. Before Capacity Performance was implemented, there was no opportunity cost from offering into the BRA and clearing, but that has changed under Capacity Performance. These changes affect existing resources with low net going-forward cost that do not need revenues from the capacity auction to remain online and sell into the energy and ancillary markets.[52] Without a capacity

[52] Offers from resources making investment decisions based on BRA outcomes are not affected by Capacity Performance to the same degree. These resources would not come online, or would retire, if they failed to clear the capacity market and therefore do not forego bonus payments on their full output by clearing the capacity auction. Investment decision offers should reflect penalties and bonuses on the *difference* between actual performance and market performance. Some investment decision offers would reflect bonus payments for outperforming the market (*e.g.*, new resources) and some would reflect penalties for under-performance (*e.g.*, old resources seeking a capacity payment to avoid retirement). The overall impact on the supply curve of changes to investment decision offers is likely small. As shown in Figure 13, available evidence shows that the upper portion of BRA supply

Continued on next page

obligation, these resources would earn bonus payments on their full output during performance hours. With a capacity obligation, they forego bonus payments on the balancing ratio (since they receive payments based on the *difference* between their performance and the balancing ratio). In order to ensure they break even by taking on a capacity obligation, these resources will offer their foregone bonus payments into the auction, as shown in Figure 14.

Figure 14 shows expected supply offers for different types of resources after accounting for Capacity Performance incentives. Resources with zero or low net going-forward cost are expected to submit a "Bonus Opportunity Cost Offer". As explained above, these resources will include the opportunity cost of foregoing bonus payments on their full output in their offer price. We directly model the impact of these offers on the lower part of the supply curve. New resources (or resources considering mothballing or retiring) will submit an "Investment Decision Offer." Since their participation in the market is contingent on clearing the capacity auction, supply offers from these resources will only be adjusted by the amount of penalty or bonus payments they expect to receive on the difference between their output and the market average. Because the adjustments will be small and offsetting between different resources, we do not directly model the impact of these offers on the upper portion of the supply curve.[53]

Continued from previous page

curves (above around $200/MW-day) do not appear to have changed with the introduction of Capacity Performance.

53 Investment Decision Offers will be greater than Net Going Forward costs for resources expecting to under-perform the market and less than Net Going Forward Cost for resources expecting to over-perform the market.

Figure 14
Adjusted Supply Offers under Capacity Performance

Bonus Opportunity Cost Offer	Investment Decision Offer
PPR × H × B	**Net Going Forward Cost - PPR × H × (A - B)**
Reflects the minimum capacity price at which capacity obligation is more profitable than earning bonus payments as an energy-only resource	Reflects minimum capacity price above which a resource will take on a capacity obligation (rather than mothball, non-entry, or retirement)

Sources and Notes:

Performance Penalty Rate (PPR) is calculated as [Net CONE ($/MW-day) * 365 days] divided by 30 hours (Net CONE is of the modeled LDA in which a resource resides). 2020/21 PPR was $2,200–$4,100/MWh across all zones. See PJM (2017c).

Resources with capacity obligations receive bonuses or are charged penalties based on the performance shortfall, or the difference between the resource's performance (A) and the Balancing Ratio (B). If the resource's shortfall is positive (A < B), then it is charged a penalty. If the shortfall is negative (A > B), then the resource may receive a bonus payment. Resources without capacity obligations receive bonuses on their full output.

These are slightly simplified formulas that apply only if Capacity Performance Bonus Rate (CPBR) = PPR. CPBR may be somewhat lower than PPR in reality due to factors such as discretionary exemptions from performance penalties, approved outages, and penalty stop-loss provisions.

See PJM (2017h), OATT Attachment DD.

As Figure 13 shows, Capacity Performance has impacted supply offers. In the three Capacity Performance BRAs, supply curves had fewer zero priced offers and higher prices in the low-priced portion of the curve compared to the non-Capacity Performance supply curves. This is consistent with the theory that resources with zero or low net going-forward costs will increase their offer price to account for the opportunity cost of the foregone bonus payments on their full output as described in Figure 14. The most dramatic change from previous auctions is the gradually increasing prices at the lower end of the Capacity Performance supply curves. The offers in this part of the curve reflect a diversity of views among market participants on the expected number of performance hours (H) that will be called during the delivery year.[54] The market's assessment of expected performance hours is a key element of our approach to modeling Capacity Performance.

We model two types of scarcity that lead to performance hours: installed capacity scarcity and operational scarcity. Installed capacity scarcity is a result of installed capacity falling below a threshold supply buffer above load. Operational scarcity is a result of generators being

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54 There is some degree of uncertainty in the value of the balancing ratio and bonus rate, though substantially less than in the number of performance hours. PJM publishes a balancing ratio in advance of the auction. While this value can vary to some degree depending on system conditions during a performance hour, it is ultimately driven by supply and demand for power. There is also some degree of uncertainty in the bonus rate. While the *penalty* rate is published in advance of the auction, the *bonus* rate may differ from the penalty rate if PJM forgives some under-performing resources or stop-loss provisions take effect. In our analysis, we assume that performance hours are the major driver of variability in Capacity Performance offers.

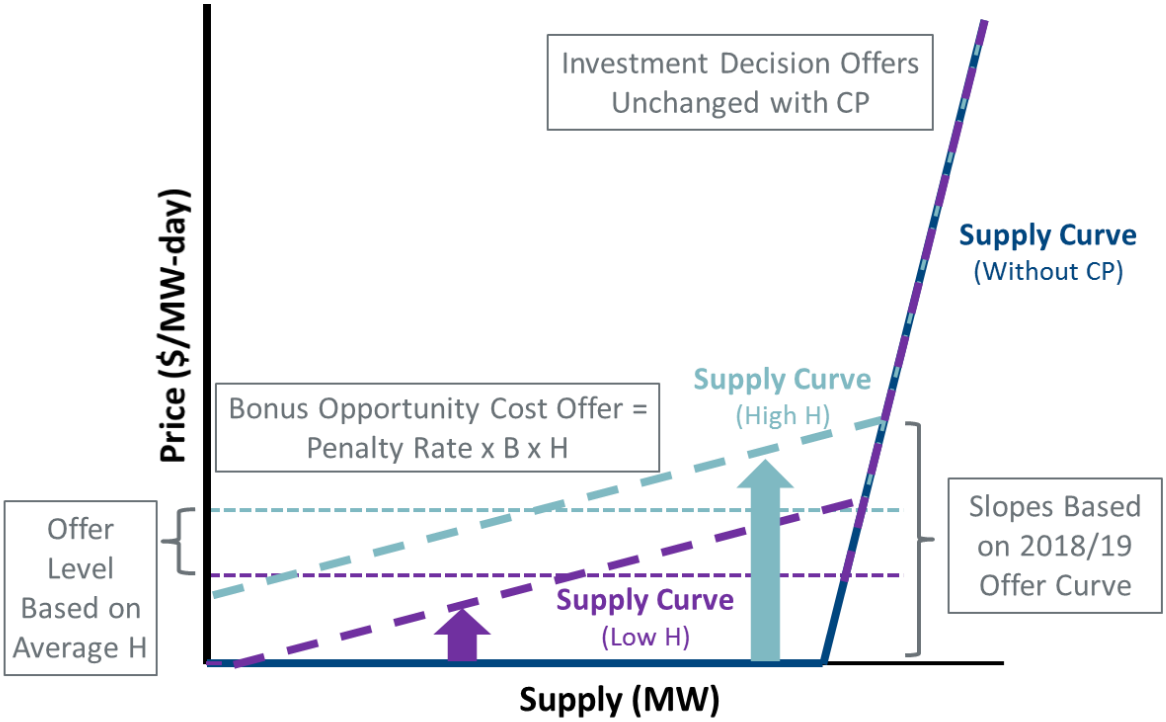
unavailable to operate to meet their obligations. For example, during the 2014 Polar Vortex, PJM had sufficient installed capacity to meet load but many plants were not available due to fuel supply or other operability constraints.

To assess installed capacity scarcity, we relied on reliability modeling data from PJM. We found that at equilibrium reserve margins, two to three performance hours are expected during an average year due to installed capacity scarcity. Due to the high reserve margins in PJM over the last few years, installed capacity scarcity performance hours were very unlikely. Most past performance events were due to operational scarcity. Using historical performance events data posted by PJM, we estimated that about seven performance hours are expected annually due to operational scarcity. Based on offer data provided by PJM, market participants expect ten performance hours on average, ranging from 0 to 30 across all participants.

We model the range of market participant expectations of H based on offers in the 2018/19 through 2020/21 Capacity Performance auctions. As we describe in more detail in Appendix B, we estimate implied performance hours in each Capacity Performance offer across these three auctions. We then fit a mixture distribution consisting of offers with zero performance hours and beta-distributed offers with performance hours between zero and 30.

Figure 15 shows a stylized depiction of our approach to generating Capacity Performance supply curves in our Monte Carlo modeling. The horizontal dashed lines of the figure show the *average* impact of installed capacity and operational scarcity on offers. The sloped lines of the figure shows the range of market participant expectations of H based on our statistical model. For each draw, we determine installed capacity scarcity performance hours based on the supply cushion in that draw, generate random operating scarcity performance hours, and then apply our statistical model to determine the dispersion of performance hours across offers. We then convert the performance hours into offers by multiplying by the penalty rate and the balancing ratio. For more detail on our Capacity Performance modeling, see Appendix B.

Figure 15
Stylized Depiction of Supply Curves with Capacity Performance



Notes:

Figures are for illustrative purposes, supply curve shapes and impact of Capacity Performance are based on offer data provided by PJM.

The energy-only offer shown in this figure slightly simplifies formulas that apply only if Capacity Performance Bonus Rate is equal to the Penalty Rate (*i.e.*, no exceptions to penalty assessment or stop-loss). Due to discretionary exemptions from performance penalties, approved outages, and penalty stop-loss provisions, the Bonus Rate may be somewhat lower than the Penalty Rate in reality.

D. Reliability Outcomes

We calculate reliability outcomes for each Monte Carlo simulation draw based on locational and system-wide reliability simulations conducted by PJM staff. We use the same simulation modeling that PJM uses to calculate the system and local resource adequacy requirements for the BRA, as described in their reliability studies.[55] In that simulation analysis, PJM estimates the relationship between the supply quantity and LOLE, with system-wide resource adequacy requirement set at the quantity needed to meet a LOLE of 0.1 events/year (or 1-in-10) and local resource adequacy requirements set at an LOLE of 0.04 events/year (or 1-in-25).[56]

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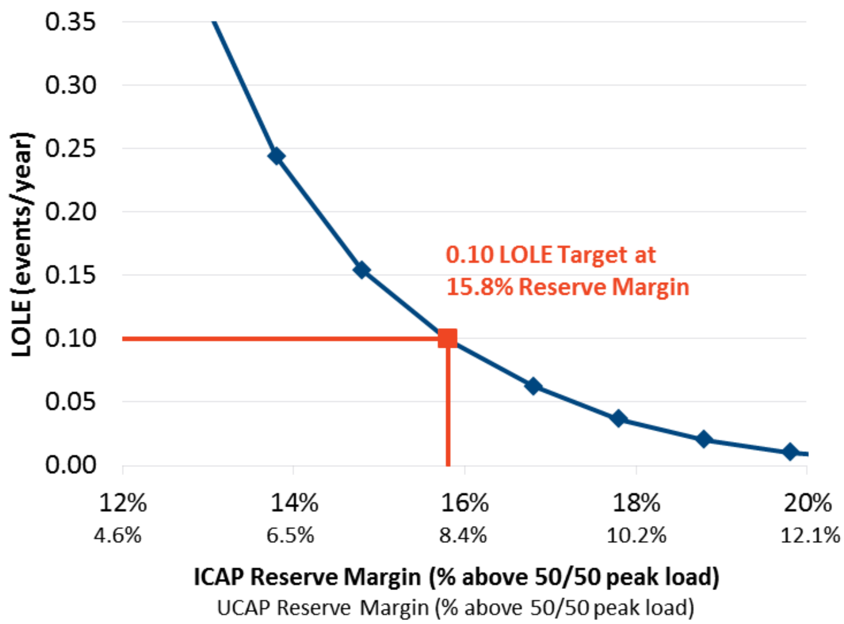
55 The reliability results shown in Figure 16 are based on PJM's preliminary 2021/22 reliability modeling. See PJM (2017i).

56 Note that the local requirement of 1-in-25 actually reflects lower total reliability, because the location is subject to local shortages as well as system-wide shortages.

Figure 16 shows the relationship between the system reserve margin and LOLE. This relationship is asymmetrical, with reliability outcomes deteriorating sharply at reserve margins below the resource adequacy requirement but improving only gradually at reserve margins above the resource adequacy requirement. An important implication of this asymmetry is that a demand curve that results in a distribution of clearing outcomes centered on the target with equal variance above and below the target will fall short of the 0.1 LOLE target on an average basis.[57]

Figure 16
LOLE vs. Reserve Margin



Sources and Notes:
LOLE data provided by PJM staff, with interpolation between discrete points and based on 2021/22 BRA parameters.

E. Fluctuations in Supply, Demand, and Transmission

To simulate a realistic distribution of price, quantity, and reliability outcomes, we introduce upward and downward fluctuations in supply, demand, administrative Net CONE, and transmission, with the magnitude of the fluctuations based on historical observation. These fluctuations have been driven by a number of different factors over the years, with a subset of examples including: (a) changes to supply economics, with individual years sometimes experiencing a wave of new offers from demand resources, imports, or new generation; (b) regulatory changes, including the 2014/15 MATS regulation; (c) rule changes that have

57 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.

resulted in increased or decreased offer quantities from categories of resources such as demand response and imports; (d) the economic recession that began in 2007, resulting in a substantial reduction in demand forecasts over the subsequent years; and (e) incorporation of supply and demand from FRR entities and territory expansions, which have tended to increase both supply and demand by similar but not exactly offsetting magnitudes, thereby introducing a net supply fluctuation into the market.

Because the magnitude of these fluctuations is an important driver of the performance of the VRR curve, we report the sensitivity of the VRR curve's performance to each type of fluctuation and conduct a sensitivity analysis regarding overall fluctuations sizes in Section IV below. We briefly describe here our approach to estimating fluctuations reflective of historical market data, and provide additional detail supporting these estimates in Appendix A.

- **Supply**: We estimate fluctuations in supply using the total quantity of supply offered in each location during each historical BRA. We de-trend the historical supply offer data and calculate deviations from the trend for each LDA. We use these deviations to determine a relationship between LDA size and deviation size and use this relationship to determine supply deviation sizes in each LDA.
- **Reliability Requirement**: We estimate fluctuations in reliability requirement in LDAs using a two-component model consisting of: (1) an RTO-correlated fluctuation that is entirely driven by the variation in historical RTO reliability requirements; and (2) an incremental fluctuation driven by variability in historical reliability requirements above the RTO value for each LDA.
- **Administrative Net CONE**: We assume that administrative Net CONE is subject to random error around its expected value. We estimate the fluctuations in administrative Net CONE in each simulation considering fluctuations in Gross CONE, based on historical variation in PJM's BLS Composite Index, minus fluctuations in historical E&AS estimates.[58]
- **Capacity Emergency Transfer Limit**: We simulate fluctuations in CETL as normally distributed with a standard deviation of 15% of the expected CETL value based on the 2020/21 parameters, with the standard deviation estimated based on historical auction data across all locations and years.

The aggregate impact of these individual fluctuations is illustrated in Table 5, where we compare historical fluctuations in net supply, both in terms of absolute value as well as de-trended values, to the simulated fluctuations. This net supply comparison, calculated as supply plus CETL minus reliability requirement, is the most important driver of price and quantity results in our

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[58] PJM's Bureau of Labor Statistics composite index is comprised of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Index for Construction Materials and Components (weighted 50%), and the BLS Producer Price Index for Turbines and Turbine Generator Sets (weighted 30%). See PJM (2017f).

modeling as well as in the historical market. Net supply comparisons capture important correlations between supply and demand, such as changes from supply and demand growth, increase scope and territory of RPM, and suppliers reacting to expected market conditions.

We report historical fluctuations in two ways: (1) as a simple standard deviation of historically observed values; and (2) as a standard deviation of the differences between the historically observed values and de-trended values over time. The first method produces larger fluctuations than the second, because removing the time trend reduces the variability of the distributions. We believe that both reference points provide a relevant basis for comparison; for example, the absolute-value approach may over-estimate fluctuations for components with a substantial time trend (*e.g.*, in reliability requirement and total supply), while the deviation-from-trend approach may under-estimate fluctuations for components that we would not expect to change substantially over time (*e.g.*, CETL and supply minus demand). As the table shows, our simulated net supply fluctuations fall between these two methods for most LDAs, and we test the sensitivity of our results to a reasonable uncertainty range.[59]

Table 5
Net Supply Fluctuations

LDA	Standard Deviation			Standard Deviation as % of 2020/21 RR		
	Historical Absolute Value *(MW)*	Historical Deviation from Trend *(MW)*	Simulation Analysis *(MW)*	Historical Absolute Value *(%)*	Historical Deviation from Trend *(%)*	Simulation Analysis *(%)*
RTO	8,870	3,392	4,048	5.7%	2.2%	2.6%
ATSI	1,728	925	1,659	11.1%	5.9%	10.6%
ATSI-CLEVELAND	489	447	875	8.3%	7.6%	14.9%
MAAC	4,963	2,126	2,681	7.5%	3.2%	4.0%
EMAAC	2,080	1,734	1,957	5.6%	4.7%	5.3%
SWMAAC	2,535	840	1,608	16.4%	5.4%	10.4%
PSEG	894	664	1,316	7.6%	5.6%	11.2%
DPL-SOUTH	226	220	311	7.5%	7.3%	10.4%
PS-NORTH	530	364	703	8.8%	6.0%	11.7%
PEPCO	1,984	846	1,249	24.9%	10.6%	15.6%
BGE	253	249	960	3.1%	3.1%	11.8%
COMED	690	639	1,420	2.6%	2.4%	5.4%
DAY	n/a	n/a	528	n/a	n/a	13.1%
PPL	1,458	166	1,237	14.8%	1.7%	12.6%
DEOK	n/a	n/a	799	n/a	n/a	12.2%

Sources and Notes:
All values calculated over 2009/10 through 2020/21 delivery years, where data were available.
See Appendix A for additional detail on standard deviations.
Standard Deviation percentages are based on each LDA's 2020/21 reliability requirement.
Dayton and DEOK have "n/a" for historical values because 2020/21 was the first time there were modeled in the BRA.

59 For a few LDAs, our simulated net supply fluctuations fall outside the range of the historical net supply fluctuations. These are generally small LDAs or LDAs with limited data history.

F. Summary of Base Case Parameters and Input Assumptions

Table 6 summarizes the Base Case input assumptions that we apply in our Monte Carlo simulation modeling. We adopt the reliability requirement, CETL, and Net CONE parameters from the 2020/21 BRA parameters, and assume that the price at which developers enter the market is equal to the administratively-estimated Net CONE. We report the standard deviation of fluctuations in each of these parameters as generated across the simulated draws.

Table 6
Base Case Parameters and Input Assumptions

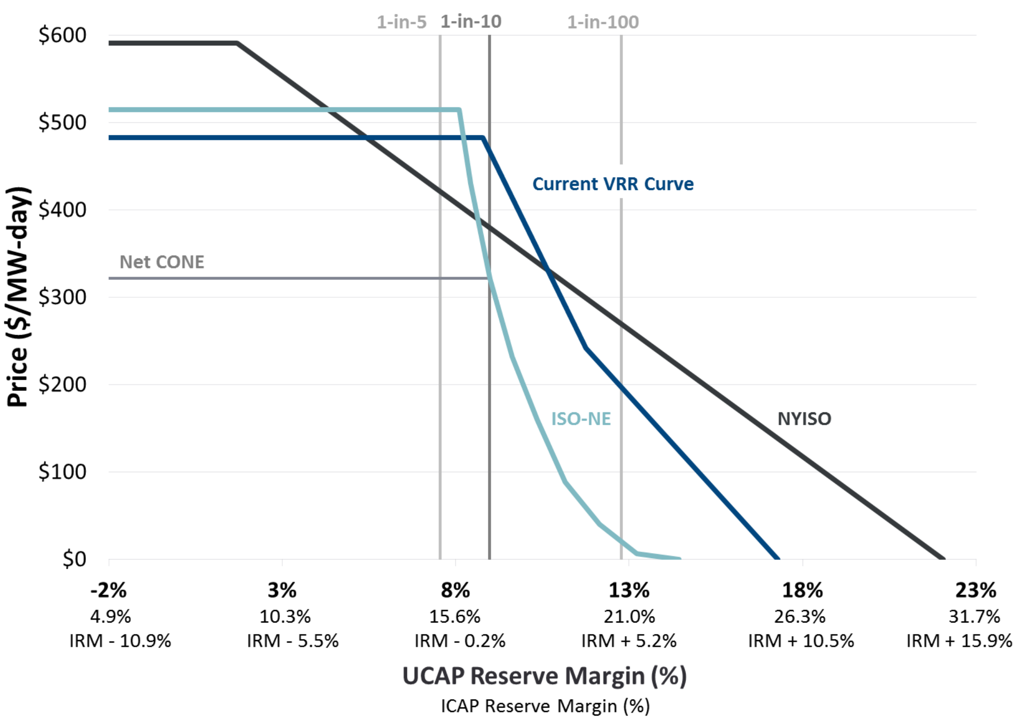
Parameter		RTO	ATSI	ATSI-C	MAAC	EMAAC	SWMAAC	PSEG	DPL-S	PS-N	PEPCO	COMED	BGE	PPL	DAY	DEOK
Average Parameter Value																
Administrative Net CONE	*($/MW-d)*	$293	$293	$293	$293	$293	$293	$307	$293	$307	$293	$330	$293	$293	$293	$293
Market Entry Price	*($/MW-d)*	$293	$293	$293	$293	$293	$293	$307	$293	$307	$293	$330	$293	$293	$293	$293
CETL	*(MW)*	n/a	9,889	5,605	4,218	8,800	9,802	8,001	1,872	4,264	7,625	4,064	6,244	7,084	3,401	5,072
Reliability Requirement	*(MW)*	154,355	15,610	5,865	66,385	36,921	15,486	11,797	2,999	6,023	7,978	26,224	8,132	9,829	4,027	7,102
Standard Deviation of Simulated Fluctuations																
Administrative Net CONE	*($/MW-d)*	$21	$20	$20	$21	$21	$22	$19	$21	$19	$22	$16	$22	$20	$20	$20
Reliability Requirement	*(MW)*	2,827	319	176	1,120	625	314	268	100	192	221	459	231	233	129	199
Reliability Requirement	*(% of RR)*	1.8%	2.0%	3.0%	1.7%	1.7%	2.0%	2.3%	3.3%	3.2%	2.8%	1.8%	2.8%	2.4%	3.2%	2.8%
CETL	*(MW)*	n/a	1,521	841	651	1,321	1,444	1,236	283	659	1,177	608	906	1,079	500	753
Supply Excluding Sub-LDAs	*(MW)*	1,320	555	126	1,783	1,306	486	230	85	170	336	1,204	184	538	85	160
Supply Including Sub-LDAs	*(MW)*	2,988	569	126	2,356	1,338	622	295	85	170	336	1,204	184	538	85	160
Net Supply	*(MW)*	4,048	1,659	875	2,681	1,957	1,608	1,316	311	703	1,249	1,420	960	1,237	528	799

Sources and Notes:
Average Parameter Values are from 2020/21 PJM Planning Parameters, see PJM (2017c).
Details on Standard Deviation of Simulated Fluctuations are provided in Appendix A.

IV. System-Wide Variable Resource Requirement Curve

The PJM VRR curve is an administrative representation of demand for capacity, supporting the primary RPM design objective of attracting and retaining sufficient supplies to meet the 1-in-10 resource adequacy standard. The downward-sloping curve supports other objectives such as mitigating price volatility, susceptibility to the exercise of market power, and rationalizing prices according to the diminishing value of reliability. As shown in Figure 17, the width of PJM's curve falls between NYISO's and ISO-NE's curve, and its price cap is somewhat lower. In this Section, we evaluate the VRR curve relative to PJM's design objectives and recommend changes. We qualitatively review its likely performance, as indicated by the curve shape, quantity at the price cap, and width. We also evaluate its performance using our probabilistic simulation model to estimate the distribution of price, quantity, and reliability outcomes associated with the curve. The evaluation in this Section is focused on the performance of the system-wide VRR curve, while we evaluate the VRR curve at the locational level in the following Section V.

Figure 17
PJM's Current VRR Curve Compared to Curves in Other Markets



Sources and Notes:

Current VRR Curve reflects the system VRR curve in the 2021/22 PJM Planning Parameters, calculated relative to the full reliability requirement, PJM (2018).

IRM is based on the 2021/22 BRA parameters, PJM (2018).

NYISO curve reported using that market's price and quantity definitions, but relative to PJM's estimate of 2021/22 Net CONE and reliability requirement. For NYISO Curve, the ratio of reference price to Net CONE is equal to 1.18 and is consistent with the NYCA curve, see NYISO (2017), Section 5.5.

ISO-NE curve applies ISO-NE's demand curve methodology using PJM data. The curve reflects the derivative of PJM's EUE vs. installed capacity curve with respect to installed capacity, stretched by a penalty factor of approximately $500,000/MWh such that the curve passes through the reliability requirement at Net CONE.

Two changes in the market since our last review require careful attention in re-assessing the VRR curve. First, as discussed in Section III.C, the introduction of Capacity Performance has increased the risk of taking on a capacity obligation and has made the supply curve more gradually sloping. In Section IV.C, we re-assess the VRR curve accounting for this effect, as well as an updated view of supply and demand in the market. The review in Section IV.C focuses on the change in VRR curve performance due to Capacity Performance and *does not* reflect the impact of revised Net CONE values.

Second, and more importantly, the decrease in Net CONE since the last auction means that the existing VRR curve must be scaled downward. In Section IV.D, we evaluate the performance of several alternative curves using revised Net CONE values. We show that continuing to set the VRR curve prices based on CT Net CONE when low-net-cost CCs are actually entering the market can be expected to attract 5% excess capacity above the resource adequacy target in equilibrium, at significant cost to customers. We recommend that PJM consider adopting a CC reference resource and left-shifting the curve by 1%. This would lower customer costs while still delivering better reliability than the curve PJM filed in 2014. We also show even more tightened curves for PJM's consideration.

A. System-Wide Design Objectives

The primary design objective of the system-wide VRR curve is to procure enough resources to maintain resource adequacy, including merchant entry when needed. This objective must be fulfilled while aiming to avoid excessive price volatility and susceptibility to market power abuse. These objectives can be at odds, with a vertical curve providing greater assurance of procuring the target quantity, but producing prices that are maximally sensitive to small shifts in supply and demand; in the other extreme, a horizontal curve provides total certainty in price but provides no certainty in the quantity that will be procured or consequently in realized reliability levels. Tradeoffs between quantity uncertainty and price uncertainty reflect the classic "prices vs. quantities" problem in regulatory economics.[60]

In order to inform these tradeoffs and determine whether the VRR curve provides a satisfactory balance, it is helpful to sharpen the definition of both the quantity-related and price-related objectives. As we discussed in our 2014 Review, we have established the following specifications in collaboration with PJM staff, consistent with PJM's Tariff, practices, and prior statements:

- **Resource Adequacy (Quantities).** Recognizing that procurement can be increased by shifting the curve up or to the right, but cleared quantities will vary as supply and demand conditions shift, our analysis assumes the VRR curve should meet the following objectives:

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60 See Weitzman (1974).

- The expected LOLE should be 0.1 events per year. This does not mean the LOLE will be 0.1 in every year, but that it can be expected to achieve the 1-event-in-10 years LOLE target on average. We will continue to maintain this interpretation of the reliability standard for the purposes of our assessment, even though we acknowledge that the current VRR Curve has been right-shifted with the explicit purpose of enhancing reliability.[61]
- Very low reserve margin outcomes should be realized from RPM auctions very infrequently. For example, there should be a relatively small probability of clearing less than "IRM – 1%," the quantity at which PJM's Tariff stipulates that a Reliability Backstop Auction would occur under certain conditions.[62]
- The curve should meet these objectives in expectation and remain robust under a range of future market conditions, changes in administrative parameters and administrative estimation errors. However, considering that future VRR curve reviews and CONE studies can adjust for major changes, it is unnecessary to substantially over-procure on an expected average basis just to ensure meeting these objectives under all conceivable future scenarios, as that would incur excess costs.

- **Prices.** Consistent with relying on merchant entry, prices can be expected to equal Net CONE on a long-run average basis (no matter what the shape of the VRR curve). But prices will vary as supply and demand conditions shift, depending on the elasticity of the supply and VRR curves. To support a well-functioning market, the VRR curve should meet the following price-volatility-related objectives:
  - The curve should achieve low price volatility, to the extent possible given other design objectives. That means reducing the impact from small variations in supply and demand, including administrative parameters, rule changes, lumpy investment decisions, demand forecast changes, and transmission parameters.
  - To mitigate susceptibility to the exercise of market power, small changes in supply should not be allowed to produce large changes in price. Mitigating susceptibility to market power and price volatility are both served by adopting a flatter VRR curve. Relatedly, a VRR curve with a moderate price cap that limits the price impact of withholding can address concerns about market power.

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61 Following our 2014 Review, PJM filed a VRR curve that was 1% right-shifted relative to Brattle's recommended curve. Based on our modeling, PJM's recommended curve would achieve an average LOLE of 0.06 events/year and was associated with customer costs approximately 1% higher than Brattle's recommended curve. PJM chose this curve on the basis that short-term supply uncertainty in the market might exceed what we accounted for in our simulation model due to a variety of policy and market factors. See paragraph 25 of Federal Energy Regulatory Commission (2014).

62 Specifically, if the BRA clears a quantity less than IRM-1% for three consecutive years. See PJM (2017h), Section 16.3.

- However, price volatility should not be over-mitigated. Prices should be allowed to vary sufficiently to reflect year-to-year changes in market conditions. It is preferred for prices to rise increasingly steeply as reserve margins decrease in order to provide a stronger price signal when needed to avoid very low reliability outcomes. Such a convex VRR shape would also make prices more proportional to the marginal reliability value, a desirable attribute for a "demand curve" for resource adequacy.[63]
- As noted above, the VRR curve needs a price cap, but it is important that the price cap binds infrequently, to prevent prices from departing too substantially from supply fundamentals.

- **Other Design Objectives.** The VRR curve forms the basis for a multi-billion dollar market, and yet it is an administratively-determined construct. To support a well-functioning market for resource adequacy in which investors and other decision-makers can expect continuity and develop a long-term view, this administrative construct should be as rational, stable, and transparent as possible.
  - The curve can be deemed "rational" if it consistently meets the design objectives outlined above, with well-reasoned and balanced choices about tradeoffs among objectives.
  - To provide stability, the curve (and RPM as a whole) should have stable market rules and administrative parameters, although adjustments may be necessary to accommodate changes in market and system conditions.
  - To support stability and transparency, the VRR curve should be simple in its definition and in how parameters are updated over time. This can avoid stakeholder contentiousness and litigation, which would increase regulatory risk for investors.

Several of these design objectives are difficult to satisfy simultaneously, and in many cases we must weigh tradeoffs among competing design objectives. For example, capacity markets can produce structurally volatile capacity prices due to steep supply and demand curves, meaning that relatively small changes in supply or demand can cause large changes in price. Introducing a sloped demand curve mitigates some of this price volatility, with flatter curves resulting in more stable capacity prices. However, a very flat demand curve will introduce greater quantity uncertainty and greater risk of low-reliability outcomes.

We evaluate the curve against the primary RPM design objective of achieving 1-in-10 LOLE on average over many years. While we and others have separately evaluated the 1-in-10 standard

[63] Since the VRR curve is designed to meet the engineering-based standard of 0.1 LOLE rather than an economics-based reserve margin, the curve can only be designed to be proportional to marginal reliability value rather than equal to the marginal economic value.

itself from reliability and economic perspectives, this is not within the scope of our present analysis.[64]

B. QUALITATIVE REVIEW OF THE CURRENT SYSTEM CURVE

Subsequent to our last review, PJM adopted a VRR curve consistent with the right-shifted convex curve we analyzed in that study. Under the assumptions in that study, the adopted curve was broadly consistent with PJM's design objectives, though the curve procured more supply than necessary to meet PJM's 1-in-10 LOLE requirement on average. PJM determined that the right-shifted curve's reduced risk of low-reliability events and its improved robustness to adverse conditions (*e.g.*, larger than expected fluctuations in net supply, administrative under-estimation of Net CONE) were worth the relatively small increase in procurement costs relative to our recommended convex curve.[65]

While PJM's current VRR curve performed well under the assumptions of our 2014 Review, it is very likely to attract too much investment under current market conditions. The current curve is based on our 2014 analysis, where we assumed entry occurs at a price approximately 2.5 times higher than our current estimate of CC Net CONE.[66] With the market entry price substantially lower, the current demand curve is likely to attract more supply than is necessary to meet the 1-in-10 standard in equilibrium. To better align the VRR curve with PJM's resource adequacy objectives, the curve could be stretched downwards and shifted to the left, as discussed below.

1. Downward-Sloping, Convex Shape

PJM's VRR curve has a downward-sloping shape to the right of point "a" as described in Section I.C above. This overall shape is consistent with PJM's design objectives, with higher prices when the system has less supply and lower prices when the system has more supply. This price and quantity relationship should attract new capacity investments when the system is short on supply, and postpone such investments when the system is long. The downward-sloping shape of the curve will also help mitigate price volatility and the exercise of market power, consistent with the design objectives.

The downward-sloping portion of PJM's curve has a convex shape (*i.e.*, curving away from the intersection of the x- and y-axis), with a steeper slope at quantities near the requirement and a flatter slope at higher quantities. A convex curve has the theoretical advantage of being consistent with the incremental reliability and economic value of capacity, as illustrated in Figure 18. The figure shows the VRR curve superimposed over the marginal avoided expected

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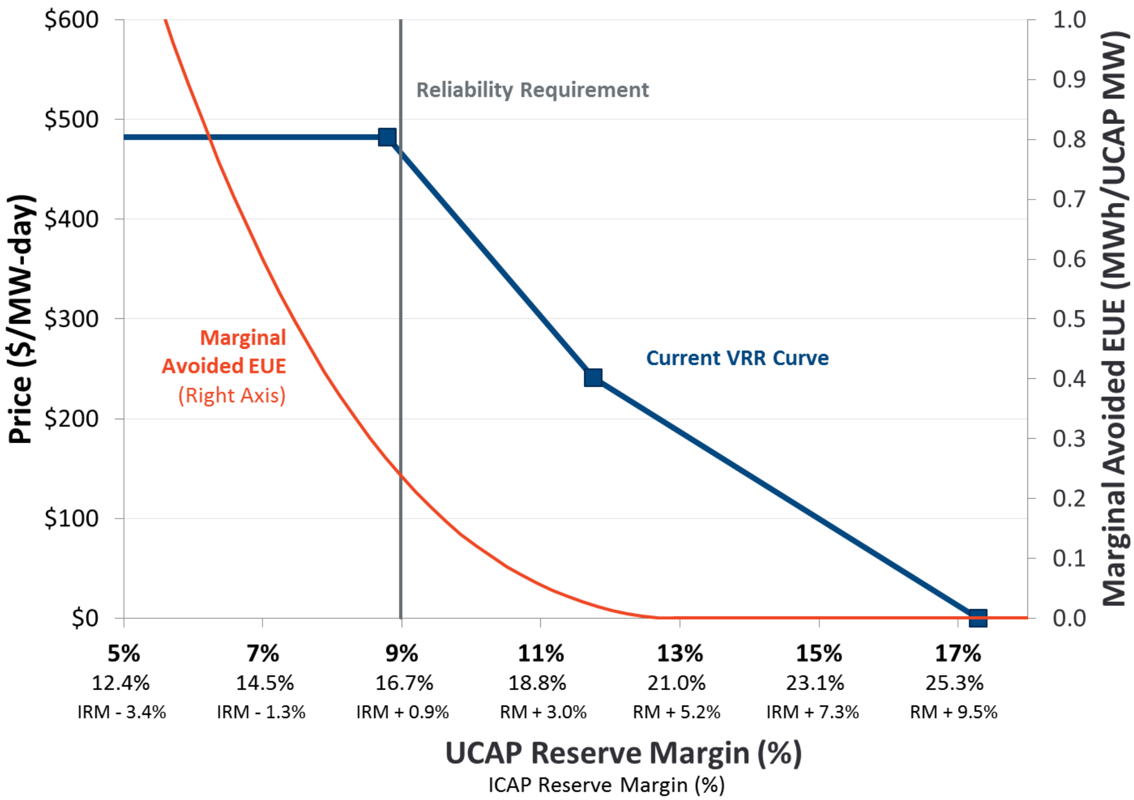
64 For example, see Pfeifenberger (2013).

65 See p. 19 of PJM's Filing Letter following the 2014 Review, PJM (2014f).

66 While based on the results of our analysis, PJM right-shifted our recommended curve by 1% to develop the current VRR curve, leading to equilibrium supply above the level needed to achieve 1-in-10 LOLE under the Net CONE value used in the 2014 Review.

unserved energy (EUE), which measures the amount of incremental load shedding that can be avoided by adding more capacity. The avoided EUE line, therefore, illustrates the estimated reliability value of increasing the reserve margin, which has a steeper slope at low reserve margins and gradually declines at higher reserve margins. The convex shape of PJM's curve reflects the economic value of adding capacity at varying reserve margins, although the total economic value of capacity includes components other than avoided EUE, such as other avoided emergency events, avoided DR dispatch, and avoided dispatch of high-cost resources.

Figure 18
2021/22 VRR Curve Compared to Marginal Avoided Expected Unserved Energy



Sources and Notes:
Current VRR Curve reflects the system VRR curve in the 2021/22 Planning Parameters, PJM (2018.).
Marginal Avoided EUE equal to Loss of Load Hours times 1 MW. Marginal EUE is based on LOLE data provided by PJM.

2. Quantity at the Cap

A convex curve with a minimum on the price cap is relatively robust from a quantity perspective. Changes to Net CONE or errors in Net CONE produce smaller reliability deviations from the resource adequacy target than they would with straight-line or concave curves. One potential drawback is that a convex demand curve will need to be wider than a straight-line curve in order to achieve reliability objectives.

The curve can be evaluated in terms of its reliability implications at varying reserve margins by comparing the VRR curve to system LOLE at varying reserve margins. The most important region of the curve from a reliability perspective is the high-priced region at reserve margins below the 1-in-10 resource adequacy requirement. This is because LOLE and other reliability metrics increase very quickly at low reserve margins, with small deviations below the requirement having a disproportionately large impact in degrading reliability while similarly-sized increases above the requirement result in relatively modest reliability improvements. For example, increasing the reserve margin from IRM to IRM+2% changes LOLE from 0.10 to 0.036 events per year, while decreasing the reserve margin to IRM-2% changes LOLE from 0.10 to 0.24 events per year. A two percentage point decrease of reserve margin thus has an impact on reliability that is more than twice as large as the impact of a two percentage point increase, and this asymmetry is even greater for larger deviations.

PJM's quantity at the cap is well to the right of its administrative reliability backstop threshold. PJM's Reliability Backstop provisions state that PJM must conduct a backstop procurement if the BRA clears below a quantity of IRM-1% for three consecutive years.[67] This IRM-1% threshold corresponds to a reliability index of 1-in-6.5, whereas point "a" corresponds to a reliability index of 1-in-9, as summarized in Table 7. This design preserves investment incentives by ensuring that PJM procures all available resources at the price cap before triggering out-of-market procurement. While the quantity at the cap should fall to the right of the Reliability Backstop to avoid suppressing investment, this consideration does not require the quantity at the cap to be so far to the right.

Table 7
Reliability at VRR Curve Quantity Points and Backstop Trigger

Quantity Point	LOLE *(Ev/Yr)*	Reliability Index *(1-in-X)*
Backstop Trigger at IRM - 1%	0.15	1-in-6.5
Point "a"	0.11	1-in-9.0
Reliability Requirement at IRM	0.10	1-in-10.0
Point "b"	0.02	1-in-47.3
Point "c"	0.00	1-in-3577.2

Sources and Notes:
Loss of Load Event (LOLE) shows the corresponding reliability for each quantity outcome shown, based on an exponential fit of LOLE and quantity as a percentage of reliability requirement. Reliability Index is the reciprocal of LOLE. Reliability data provided by PJM.

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[67] See Section OATT Attachment DD.16 PJM (2017h)

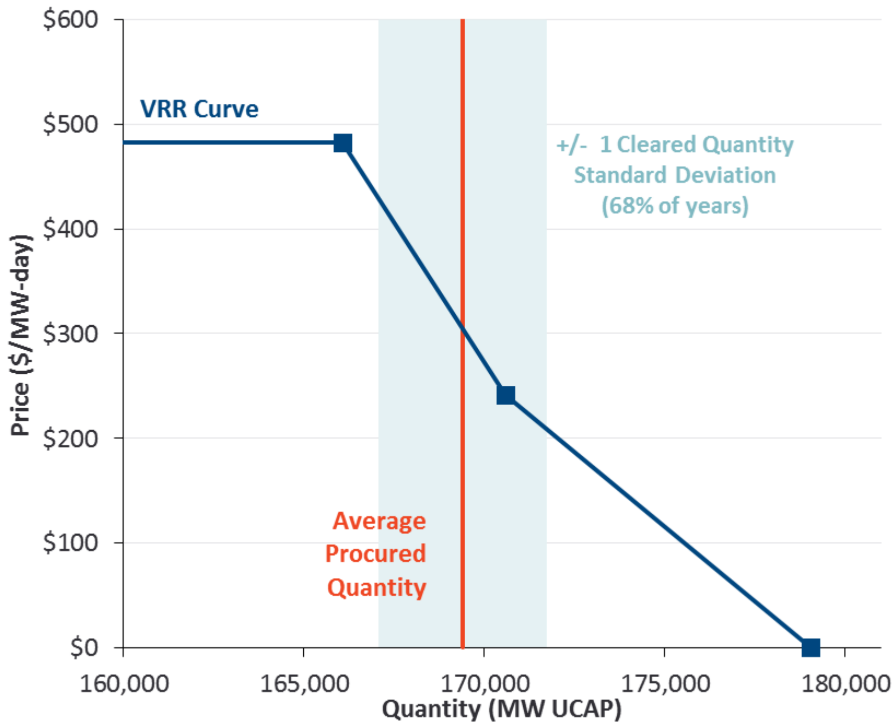
3. VRR Curve Width

Another driver of the curve's performance is the width of the curve compared to year-to-year fluctuations in supply and demand. Capacity markets are structurally volatile, both because the supply curve is quite steep at high prices and, in the case of PJM and other markets with convex demand curves, because the demand curve is steep in the high-priced region. In contrast, the flat slope of the supply curve in the low-price range provides meaningful volatility mitigation benefits. This is why, with a vertical demand curve, a capacity market would be subject to extreme price volatility with even small changes to supply or demand causing large changes in price. To mitigate this structural price volatility, the VRR curve must be flat enough (or "wide" enough) to moderate the magnitude of price changes in the face of reasonably expected fluctuations to supply and demand.

Figure 19 shows the VRR curve width compared to expected supply fluctuations simulated in our Base Case model run. We find that the cleared supply can be expected to change by a relatively substantial quantity each year, with a standard deviation of 1.4% of the reliability requirement or 2,330 MW total using simulated results.

Figure 19

VRR Curve Width Compared to Expected Cleared Supply Fluctuations



Sources and Notes:

The standard deviation of procured supply is based on simulated outcomes of our Base Case model run. The standard deviation of procured supply in this run is 2,330 MW for the RTO.

Average procured quantity is calculated using the results of our Base Case model run that uses the 2020/21 BRA parameters.

These year-to-year changes in cleared supply are relatively large compared to the width of the VRR curve. As Figure 19 shows, if starting at the average cleared quantity from our reliability modeling, losing one standard deviation of cleared supply would increase prices to near the cap by a delta of about \$115/MW-day or 38% of Net CONE; while adding one standard deviation of net supply would decrease prices by about \$87/MW-day or 30% of Net CONE. The consequence of these relatively large deviations in cleared supply, combined with PJM's current and past VRR curves, is that RPM has produced relatively volatile price outcomes.

The magnitude of expected shifts to cleared supply has important implications for reliability. For example, if prices need to be at Net CONE on average in long-run equilibrium, then assuming a normal distribution in cleared supply fluctuations, we would expect quantities at IRM-1% (reliability index 1-in-6.5) approximately once every 14 years and at IRM-3% (reliability index 1-in-2.6) approximately once every 42 years. However, supply fluctuations have not historically resulted in low realized reserve margins, largely because RPM has been maintaining an average reserve margin well in excess of the long-run equilibrium quantity.

C. Simulated Performance With Prior Net CONE and Market Entry Price

We use the probabilistic modeling approach described in Section III to evaluate VRR curve performance. In order to first isolate the impact of Capacity Performance and allow for comparison with the results of our 2014 Review, this section retains the same assumption as the prior review: that the market entry price (i.e., the price at which developers are willing to enter the market, or the true cost of entry) and the administrative Net CONE value used to define the VRR curve are both equal to the parameter from the most recent auction.[68] We estimate the distribution of system-level price, quantity, and reliability outcomes that PJM's VRR curve will achieve given Capacity Performance and expected fluctuations in supply, demand, and transmission.[69] We then test the sensitivity of the curve's performance to different assumptions about the fluctuation sizes and the impact of Capacity Performance on supply offer prices. Finally, we compare simulated performance of the VRR curve to alternative curve shapes and re-examine the 1% right-shift adopted in the prior review.

We will separately address in Section IV.D the implications of recent reductions in the market entry price. Our two-stage analytical approach allows us to show that (1) Capacity Performance

68 The prior review assumed the market entry price and administrative RTO Net CONE were \$331/MW-day, taken from the 2016/17 BRA parameters. The new simulations in this section assume \$293/MW-day, taken from the 2020/21 BRA parameters. However, the specific value does not significantly affect simulated reliability. What does matter is the assumption that the administrative value used to set prices in the VRR curve are equal to the true value developers need to earn in order to invest.

69 Our analysis in this and the following section uses updated supply, demand, and transmission parameters reflecting the current state of the system. However, because these parameters did not change substantially from our 2014 Review, they are not a major driver of our results.

and other changes to supply and demand in the market (other than the market entry price) have not substantially affected the reserve margins and capacity prices PJM's VRR curve can be expected to achieve in a long-run equilibrium; and (2) Reductions in the market entry price and the choice of reference technology used in setting administrative Net CONE do have a major impact on VRR curve performance, as shown in Section IV.D.

1. Effect of Capacity Performance

Our analysis suggests that Capacity Performance has little impact on VRR Curve performance. Table 8 shows that simulated reliability is approximately 0.06 LOLE both with and without Capacity Performance and other more minor model updates. As we discussed in Section III.C, Capacity Performance primarily impacts the low-priced portion of the supply curve (see Figure 13). With low-priced offers increasing on average and more supply in the gradually sloping portion of the supply curve, price volatility decreases, as shown in Table 8 and Table 9. Simulated reliability is largely unaffected, as that is primarily driven by the high-price portion of the supply curve that does not change under Capacity Performance.

This does not mean Capacity Performance has no impact on reliability. Capacity Performance presumably improves operational performance in ways that are not captured in our reliability metrics that consider only reserve margins.

Table 8
Performance of Current VRR Curve Compared to 2014 Study Results
Both Assume Market Entry Occurs at the Price Corresponding to Administrative Net CONE

	Price			Reliability				
	Average (= Market Entry Price)	Standard Deviation	Frequency at Cap	Average LOLE	Average Excess (Deficit)	Reserve Margin Standard Deviation	Frequency Below Reliability Requirement	Frequency Below 1-in-5
	($/MW-d)	*($/MW-d)*	*(%)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*
2014 Study w/ VRR Curve (no CP)	$331	$107	13%	0.060	1.7%	1.9%	16%	7%
2017 Study w/ VRR Curve (w/CP)	$293	$87	10%	0.064	1.8%	1.7%	13%	5%

Sources and Notes:
Prices are reported in dollars per UCAP MW per day.
2014 results use the right-shifted VRR curve that PJM adopted, under the assumption that the market entry price and administrative Net CONE are both equal to the 2016/17 BRA parameter value.
2017 results use PJM's current VRR curve under the assumption that the market entry price and administrative Net CONE are both equal to the 2020/21 BRA parameter value.

2. Sensitivity to Uncertainties in Capacity Performance and Fluctuations

We test the robustness of VRR curve performance to the primary drivers of our results using a sensitivity analysis on our modeling assumptions, as summarized in Table 9. We first test the sensitivity of our results to the size of fluctuations in supply and demand, by individually eliminating supply fluctuations, then eliminating demand fluctuations. We then evaluate our results if all fluctuations are 33% larger or 33% smaller than their Base Case values. We also evaluate performance under alternative assumptions about how the market will respond to Capacity Performance, and to fluctuations in administrative Net CONE.

As expected, eliminating or reducing the size of fluctuations reduces variability in price and quantity and improves reliability. Eliminating supply and demand fluctuations both have a similar impact on results, which is expected given that the size of supply and demand fluctuations are approximately equal (see Table 5). Results are relatively insensitive to assumptions about Capacity Performance. Reliability improves very slightly if all supply resources offer based on 30 performance hours and degrades very slightly if supply resources do not account for Capacity Performance at all. Results are also relatively insensitive to the size fluctuations in administrative Net CONE.

Comparing cases with higher and lower fluctuation sizes, we note the substantial asymmetry in reliability results. Decreasing fluctuation sizes by 33% reduces LOLE by 0.012 (from 0.064 to 0.052) events per year, while increasing fluctuations by 33% increases LOLE by 0.026 (from 0.064 to 0.090), a change nearly 120% larger in magnitude. This asymmetry is caused by the convexity of the LOLE curve: its relative steepness at low reserve margins and relative flatness at high reserve margins. The higher fluctuation size case increases the frequency of low reserve margin outcomes that contribute a disproportionately large number of reliability events, while the greater number of very high reserve margin outcomes have a relatively smaller reliability benefit due to the flatter slope of the LOLE curve in that region.

Table 9

Performance of Current VRR Curve under Base Case and Sensitivity Assumptions

All Cases Assume Market Entry Occurs at 2020/21 BRA Administrative Net CONE

	Price and Procurement Costs				Reliability				
	Average Price (= Market Entry Price)	Standard Deviation of Price	Frequency at Cap	Average Cost (P × Q)	Average LOLE	Average Excess (Deficit)	Reserve Margin Standard Deviation	Frequency Below Reliability Requirement	Frequency Below 1-in-5
	($/MW-d)	*($/MW-d)*	*(%)*	*($mil)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*
Base Case	$293	$87	10%	$17,087	0.064	1.8%	1.7%	13%	5%
33% Increase in Fluctuations	$293	$99	16%	$17,096	0.090	1.7%	2.3%	18%	8%
33% Decrease in Fluctuations	$293	$72	5%	$17,088	0.052	1.9%	1.2%	7%	2%
No Supply Fluctuations	$293	$76	6%	$17,134	0.053	1.9%	1.3%	8%	2%
No Demand Fluctuations	$293	$75	6%	$17,060	0.053	1.9%	1.3%	8%	2%
No Net CONE Fluctuations	$293	$86	10%	$17,084	0.063	1.8%	1.7%	12%	4%
No Capacity Performance	$293	$96	12%	$17,075	0.067	1.9%	2.0%	15%	6%
Implied H = 30	$293	$73	8%	$17,094	0.059	1.8%	1.4%	9%	3%

Notes:

Prices are reported in dollars per UCAP MW per day.

Results use PJM's current VRR curve under the assumption that the market entry price and administrative Net CONE are both equal to the 2020/21 BRA parameter value.

3. Re-Evaluation of the Left-Shift of the VRR Curve

In 2014, PJM filed a 1% right-shifted curve relative to our recommended curve on the basis that the market was facing substantial uncertainty in supply in the coming years. PJM and the FERC Order cited several drivers of this uncertainty: large scale generation retirements due to the Mercury and Air Toxics Standards, low-priced shale gas, increasing efficiency of gas combined-cycle technology, the D.C. Circuit court's *vacatur* of FERC's Order 745, and the implementation of the EPA's Clean Power Plan.[70] Due to these considerations, PJM placed more weight on the risk of very low reliability events and on our "stress" cases involving high supply uncertainty and administrative under-estimation of Net CONE. PJM concluded that a 1% right-shifted curve would help it ride through any potential supply disruptions, while acknowledging that it might lead to reliability better than 1-in-10 in the long-run average.

Most of the reasons for right-shifting the VRR curve that PJM cited in its 2014 filing are no longer applicable. While we acknowledge the ongoing potential for retirement by plants not covering their fixed costs, these economic retirements do not pose the same resource adequacy challenge as the risk of simultaneous large-scale retirements under MATS. PJM's market has demonstrated its ability to manage economic retirements by attracting new capacity or incentivizing incumbents to stay online as the market tightens. As a result, we would recommend shifting the VRR curve back to the left, even if no changes to the market entry price had occurred. Table 10 compares the performance of PJM's current curve to a 1% left-shifted curve under the assumption that the market entry price and administrative Net CONE both equal the 2020/21 BRA parameter. The left-shifted curve achieves average LOLE of approximately the 1-in-10 standard. Customer costs decrease by approximately $150 million per year, or 1% of the total. The frequency of low reliability events (below 1-in-5) increases slightly, but such events would still be rare.

70 See paragraph 25 of Federal Energy Regulatory Commission, 2014xa.

Table 10
Performance with a Left-Shifted Curve
Assuming Market Entry Occurs at the 2020/21 BRA Administrative Net CONE

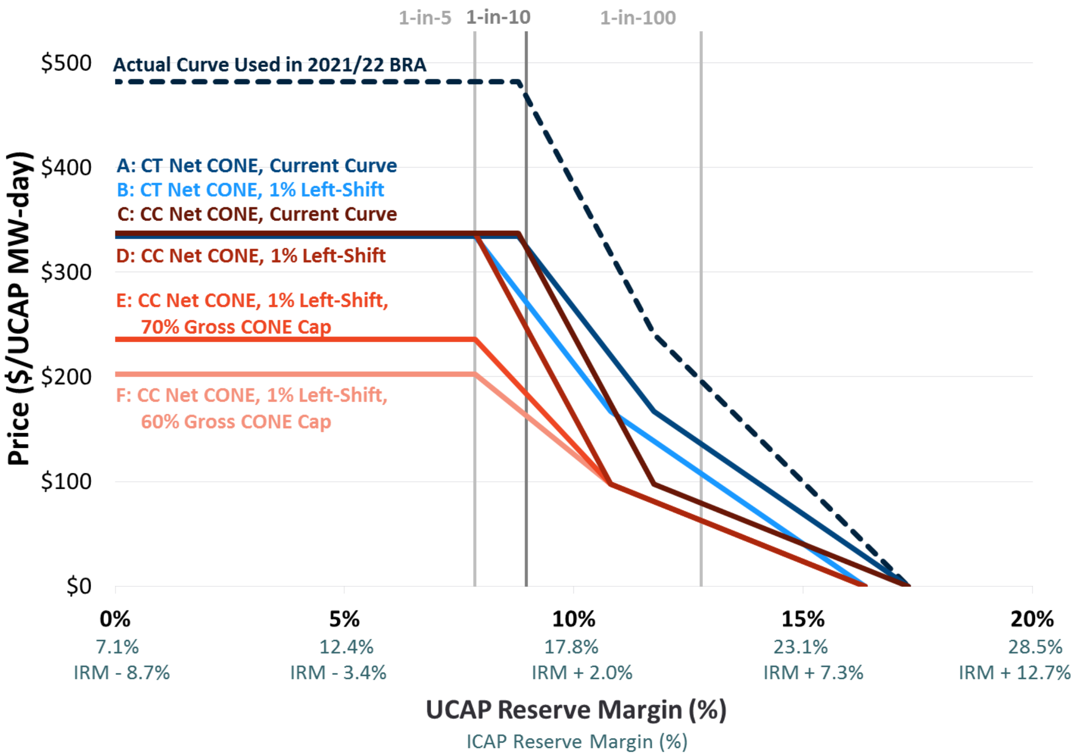
	Price and Procurement Costs				Reliability				
	Average Price (= Market Entry Price)	Standard Deviation of Price	Frequency at Cap	Average Cost (P × Q)	Average LOLE	Average Excess (Deficit)	Reserve Margin Standard Deviation	Frequency Below Reliability Requirement	Frequency Below 1-in-5
	($/MW-d)	*($/MW-d)*	*(%)*	*($mil)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*
Current VRR Curve	$293	$87	10%	$17,087	0.064	1.8%	1.7%	13%	5%
Left-Shifted Curve	$293	$86	10%	$16,941	0.098	0.8%	1.7%	27%	8%

Notes:
Prices are reported in dollars per UCAP MW per day.
Results use PJM's current VRR curve under the assumption that the market entry price and administrative Net CONE are both equal to the 2020/21 BRA parameter value.

D. Simulated Performance With Updated Net CONE

This section assesses the performance of the five candidate VRR curves shown in Figure 20. All curves are analyzed under the assumption that developers enter the market until expected prices are equal to our estimate of CC Net CONE. This assumption is consistent with ample evidence presented in Section II.B that combined-cycle plants are currently the market's resource of choice. Given the similar Gross CONE for new CCs and new CTs and the large E&AS advantage enjoyed by the CC, the CC is likely to remain the more economic resource under most foreseeable conditions.

Figure 20
Candidate System VRR Curves



Notes and Sources:

CC and CT curves are based on the level-nominal estimates of Gross CONE with major maintenance in VOM, our recommendation to use the median LDA E&AS margin as the RTO value, and apply PJM's backward-looking E&AS methodology for the CT estimate and forward-looking approach for the CC estimate.

2021/22 BRA curve uses unadjusted values posted in the 2021/22 BRA parameters, PJM (2021/22).

1. Simulated Performance of Candidate Curves

The VRR curve that PJM selects will have implications for both reliability and customer costs.[71] In this section, we describe each candidate curve in more detail and summarize the reliability and customer cost impacts developed using our simulation model. Table 11 summarizes the performance of all candidate curves assuming developers enter the market until expected prices are equal to our estimate of CC Net CONE (the market entry price).

A. **Current VRR Curve with Updated CT Net CONE** (shown in **blue**). With a simple downward adjustment to the current VRR curve reflecting the updated CT Net CONE estimate, the curve would remain high relative to the lower costs at which entry has been

71 No matter which VRR curve PJM adopts, we expect supply to enter or exit the market until the average clearing price across simulation draws is equal to $129/MW-day (UCAP), the market entry price for a CC. The higher, right-shifted curves would not increase the long-term equilibrium price (although they might affect prices in the short-term). They will, however, procure more supply, at a cost to customers.

occurring. This procures substantially more supply than needed to meet the 1-in-10 LOLE standard. Simulated long-run reserve margins are 4.3% above target on average and limit expected annual loss-of-load events (LOLE) to 0.011—approximately ten times more reliable than PJM's resource adequacy standard of 0.1 events per year.

B. **1% Left-Shifted Curve with CT Net CONE** (shown in **light blue**). Relative to curve **A,** curve **B** would reduce the supply in the market by 1% and thus reduce annual procurement costs by $74 million, and yet still achieve LOLE of 0.023, more than four times better than the standard. The 1% left-shift undoes the right-shift that PJM implemented four years ago. We recommend undoing the prior shift because most of the regulatory and market conditions that helped justify the right-shift of the demand curve have now been resolved.[72]

C. **Current VRR Curve with CC Net CONE** (shown in **dark red**). Similar to curve **A**, but this curve applies a greater downward adjustment to align the curve with the prices at which new capacity is available. However, the high CC E&AS offset triggers the alternative price cap provision of PJM's tariff, under which the cap is raised to Gross CONE when Net CONE falls below 2/3 of Gross CONE. The alternative price cap at Gross CONE lifts the price cap to approximately 2.6 × Net CONE and stretches the left half of the curve upward, supporting greater entry. Compared to curve **A** that reflects the CT Net CONE estimate, this curve decreases excess capacity by 1.5%, reducing procurement costs by $100 million. Expected reserve margins are still 2.8% above the resource adequacy target and expected LOLE is 0.031, over three times better than the resource adequacy standard.

D. **1% Left-Shifted Curve with CC Net CONE** (shown in **medium red**). Similar to curve **C**, but left-shifted. The reliability performance of this curve is approximately 0.05 LOLE per year, still exceeding the 0.1 LOLE target by a factor of nearly 2 on average and falling below the IRM target in only 5% of all simulated years. Even if the true market entry price were 20% higher than the CC Net CONE estimate that is used to anchor the VRR curve, simulated LOLE would be 0.072. This curve results in annual capacity procurement costs that are $96 million less than under the curve **B** and $71 million less than under curve **C**.

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72 We understand that PJM right-shifted the curve we had recommended based on simulations, in part because of short-term drivers of supply uncertainty that may not have been fully captured in our modeling at the time, including Mercury Air Toxics Standards retirements, low gas prices, EPA's Clean Power Plan, and the D.C. Circuit Court's *vacatur* of FERC Order 745. Many of these challenges are no longer a concern, and the market has demonstrated robust replacement of retiring resources. While we acknowledge the ongoing potential for retirement by plants not covering their fixed costs, these economic retirements do not pose the same resource adequacy challenge as the risk of simultaneous large-scale retirements under MATS. PJM's market has demonstrated its ability to manage economic retirements by attracting new capacity or incentivizing incumbents to stay online as the market tightens.

E. **1% Left-Shifted Curve with CC Net CONE and Alternative Price Cap at 0.7 × Gross CONE** (shown in red). Reducing the alternative price cap to a lower multiple of Gross CONE would help to align performance with the reliability standard. If the administrative Net CONE value anchoring the curve accurately reflects the market entry price, simulated reserve margins for this curve exceed the resource adequacy target by 1.4% on average and achieve an average LOLE of 0.071. Annual average procurement costs are $42 million lower than curve D. If the true market entry price were 20% higher than the estimated value used to anchor the VRR curve, average LOLE would reach 0.163, somewhat worse than the resource adequacy target. As we discuss further below, this curve strikes a reasonable balance between performance with accurate Net CONE and exposure to stress conditions. This is our recommended curve.

F. **1% Left-Shifted Curve with CC Net CONE and Alternative Price Cap at 0.6 × Gross CONE** (shown in light red). This curve further reduces the alternative price cap to 0.6 × Gross CONE, resulting in a price cap approximately equal to 1.5 × Net CONE. Simulated reserve margins for this curve still exceed the target by 1.1% on average and achieve an average LOLE of 0.091. However, reserve margins fall below the resource adequacy target during 20% of all simulated years. Moreover, in a stress case in which true market entry price is 20% higher than the value used to anchor the VRR curve, average LOLE climbs to 0.331, substantially worse than the resource adequacy requirement.

Table 11
Simulated Performance of Candidate VRR Curves
*All Cases Assume Market Entry Occur at Estimated CC Net CONE of $129/MW-day**

	Admin Net CONE	Price and Procurement Costs			Reliability					
		Avg. Price (= Market Entry Price)	Standard Deviation of Price	Average Cost (P × Q)	Average LOLE	Stress LOLE *	Average Excess (Deficit)	Reserve Margin Standard Deviation	Frequency Below Reliability Requirement	Frequency Below 1-in-5
	($/MW-d)	*($/MW-d)*	*($/MW-d)*	*($mil)*	*(Ev/Yr)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*
CT as Reference Technology										
A: Current Curve	$222	$129	$34	$8,139	0.011	0.023	4.3%	1.1%	0%	0%
B: 1% Left-Shift	$222	$129	$34	$8,065	0.023	0.041	3.3%	1.1%	0%	0%
CC as Reference Technology										
C: Current Curve	$129	$129	$58	$8,039	0.031	0.046	2.8%	1.1%	1%	0%
D: 1% Left-Shift	$129	$129	$58	$7,969	0.053	0.072	1.8%	1.1%	5%	0%
E: 1% Left-Shift, 70% Gross CONE Cap	$129	$129	$50	$7,927	0.071	0.163	1.4%	1.5%	15%	4%
F: 1% Left-Shift, 60% Gross CONE Cap	$129	$129	$46	$7,906	0.091	0.331	1.1%	1.7%	20%	6%

Notes:
Prices are reported in dollars per UCAP MW per day.
Gross CONE values used in the simulation modeling are trivially (<1%) different from the final values developed in our CONE study.
* "Stress LOLE" assumes the realized market entry price exceeds our estimated CC Net CONE by 20%.

In addition to our analysis presented above, PJM requested that we simulate the performance of the same curves under the assumption that new capacity does not enter at our estimate of CC Net CONE, but only at a market entry price given by our much higher estimate of CT Net CONE. This describes a different world from the one we have observed in recent auctions with plentiful

CC entry at low prices consistent with our cost analysis. It assumes CCs become unable or unwilling to enter except at capacity prices more than 70% above our estimates. Table 12 shows that, under this assumption, our recommended curve (E) would not maintain reliability in the long run. Curves C and D still achieve reasonable reliability due to their high price caps. Our long-run equilibrium model is not suitable for evaluating the curve with 60% Gross CONE price cap (F) under these conditions, since the price cap is below the market entry price. (And if PJM were to actually under-estimate Net CONE so severely as to fail to attract entry even at the price cap, it would likely correct the error for future auctions, while undertake out-of-market actions if necessary to ensure resource adequacy in the short-term.)

Table 12
Simulated Performance of Candidate VRR Curves under Assumptions Requested by PJM
All Cases Assume Market Entry Occur at Estimated CT Net CONE of $222/MW-day

	Admin Net CONE	Price and Procurement Costs			Reliability				
		Avg. Price (= Market Entry Price)	Standard Deviation of Price	Average Cost (P × Q)	Average LOLE	Average Excess (Deficit)	Reserve Margin Standard Deviation	Frequency Below Reliability Requirement	Frequency Below 1-in-5
	($/MW-d)	($/MW-d)	($/MW-d)	($mil)	(Ev/Yr)	(IRM + X%)	(% ICAP)	(%)	(%)
CT as Reference Technology									
A: Current Curve	$222	$222	$66	$13,020	0.063	1.8%	1.7%	13%	5%
B: 1% Left-Shift	$222	$222	$66	$12,909	0.098	0.8%	1.7%	26%	8%
CC as Reference Technology									
C: Current Curve	$129	$222	$82	$12,938	0.088	1.1%	1.7%	20%	7%
D: 1% Left-Shift	$129	$222	$82	$12,827	0.133	0.1%	1.7%	40%	12%
E: 1% Left-Shift, 70% Gross CONE Cap	$129	$222	$40	$12,534	0.610	-2.6%	2.8%	82%	58%
F: 1% Left-Shift, 60% Gross CONE Cap		Long-run equilibrium model is not suitable for this case							

Notes:

Prices are reported in dollars per UCAP MW per day.

Gross CONE values used in the simulation modeling are trivially (<1%) different from the final values developed in our CONE study.

Our model does not produce sensible results for a case in which market entry occurs at the CT Net CONE and the VRR curve is anchored at the CC Net CONE with a minimum price cap at 60% of Gross CONE. Under these conditions, the price cap is approximately $200, while Net CONE is $222, precluding a long-run equilibrium.

2. Alternative Price Cap with a CC Reference Resource

As discussed above, PJM could reduce the alternative price cap triggered by a CC reference resource if it wanted to avoid procuring more capacity than needed to just meet the 1-in-10 resource adequacy target. Candidate curves E and F include a reduced alternative price cap. While reducing the alternative price cap will reduce customer costs, there is a trade-off with higher risk of extreme low reliability in stress conditions.

We evaluated curves with a range of alternative price caps in order to inform PJM's choice of the appropriate level for the alternative price cap. Table 13 shows that as the alternative price cap is reduced, average LOLE increases, bringing it closer to the 1-in-10 target. If the price cap is set to

0.6 × Gross CONE, such that it corresponds to approximately 1.5 × Net CONE for a CC, average LOLE is closest to the 1-in-10 target.

However, a curve with a price cap of 0.6 × Gross CONE (curve **F** in Figure 20) would not effectively protect against the possibility that capacity will not enter at the price we estimated for CC Net CONE. Under a stress case where the market entry price is 20% higher than the parameter used to anchor the VRR curve, resource adequacy risk can increase well above 1-in-10 and simulated average LOLE rises to 0.331. This is exactly the kind of outcome the higher price cap was originally intended to protect against when low Net CONE would otherwise flatten the curve and magnify the reserve margin impacts of Net CONE estimation errors.[73]

Setting the minimum price cap to 0.7 × Gross CONE (consistent with curve **E** in Figure 20) strikes a better balance of aligning with the 1-in-10 standard, keeping customer costs low, and performing well under stress scenarios. A left-shifted curve with price cap at 0.7 × Gross CONE (equals 1.8 × Net CONE) would achieve simulated LOLE of 0.071 on average, still better than the 0.1 target. If the administrative Net CONE parameter is 80% of the market entry price, average LOLE would rise to 0.163. This implies resource adequacy worse than the standard, but better than the level of performance of the accepted existing VRR curve under the same stress scenario from our 2014 Review.[74]

Table 13
Left-Shifted Curves with Reduced Alternative Price Cap, with CC as Reference Technology
All Cases Assume Market Entry Occurs at Estimated CC Net CONE of $129/MW-day

	Average LOLE		
	Admin = Market	Admin = 0.8 × Market	Admin = 1.2 × Market
	(Ev/Yr)	*(Ev/Yr)*	*(Ev/Yr)*
Min Cap at 0.6 × Gross CONE (F)	0.091	0.331	0.053
Min Cap at 0.7 × Gross CONE (E)	0.071	0.163	0.048
Min Cap at 0.8 × Gross CONE	0.061	0.105	0.045
Min Cap at 1.0 × Gross CONE (D)	0.053	0.072	0.041

Notes:
Gross CONE values used in the simulation modeling are trivially (<1%) different from the final values developed in our CONE study.
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.
Market entry price is set to the Brattle CC Net CONE estimate.

73 See Pfeifenberger *et al.* (2011).

74 Accepted VRR curve under the 20% under-estimate stress scenario resulted with a LOLE of 0.182. See Pfeifenberger *et al.* (2014).

E. SUMMARY AND RECOMMENDATIONS FOR THE SYSTEM-WIDE VRR CURVE

We conclude that maintaining the CT as the reference technology for anchoring the VRR curve would procure more capacity than needed given the likely entry of CCs at a lower cost. To better align the curve with the cost at which capacity is actually available and with PJM's objective to meet resource adequacy requirements cost-effectively, we recommend adopting CCs as the reference technology. Furthermore, our simulations indicate that shifting the curve 1% left and reducing the alternative price cap to 0.7 × Gross CONE (curve **E**) would better meet and not exceed resource adequacy objectives. Simulated reliability slightly exceeds the 1-in-10 standard, with a reserve margin exceeding the target IRM 85% of the time, assuming administrative Net CONE reflects the true price developers need to enter. If the true value were 20% higher than the value applied to the VRR curve, reliability would fall short of the requirement but not nearly as much as with alternative curves with the lower cap; reliability would exceed that of the accepted existing VRR curve under the same stress scenario from our 2014 Review.[75,76] With $140 million lower annual average procurement costs than with the left-shifted CT-based curve (curve **B**), this curve seems to represent a reasonable tradeoff between cost and performance under adverse conditions. Curve **E** is therefore the VRR curve we recommend.

Shifting from the current curve (**dark blue** dashed line) to our recommended curve (**E**) is a substantial change that might raise concerns about market stability and reliability. It is true that this change risks under-procuring capacity if our estimate of CC Net CONE is much lower than the actual price at which developers will enter the next several auctions. However, this seems unlikely based on our CONE study and recent history with robust entry at low prices. For example, if this curve had been in place for the 2020/21 BRA, the auction would likely still have cleared more than 3% above the IRM target.

However we see an argument that a CT-based curve would more strongly guarantee resource adequacy under all conditions, at a cost that is modest when put in context. A $140 million difference in procurement costs (compared to curve **B**) is less than 0.5% of PJM's total annual wholesale costs. Overall, PJM's market-based resource adequacy construct appears to have saved much more than that by attracting and retaining a wide range of resources at competitive market prices well below the estimated cost of new plants.[77]

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75 We also evaluated the impact of lowering the alternative price cap to 0.8 × Gross CONE, which achieves expected LOLE of 0.061, and 0.105 in the "stress case."

76 Accepted VRR curve under the 20% under-estimate stress scenario resulted with a LOLE of 0.182. See Pfeifenberger *et al.* (2014).

77 See Pfeifenberger *et al.* (2008, 2011, and 2014).

V. Locational Variable Resource Requirement Curves

Resource adequacy challenges in the Locational Deliverability Areas (LDAs) level are of a different nature than for the system. The impact of fluctuations in transmission import limits and supply can be large in percentage terms, which can substantially impact local reserve margins. RPM's pricing dynamics play a key role in supporting local resource adequacy. The clearing price in the parent zone acts as a price floor for the LDA, with the LDA price-separating above the parent only when import limits are binding. This dynamic tends to limit downside price volatility in the LDA, attract local supply, and support reliability. However, LDAs with significantly higher Net CONE than their parent areas will have to price separate more frequently in order for average clearing prices to provide the Net CONE premium, and with lower reliability in those instances.

Our analysis of VRR curves for the LDAs focuses on these dynamics, rather than the impact of recent low market entry prices and the choice of reference technology. Our analysis of locational performance simply assumes that administrative Net CONE and the market entry price are equal to each other (using the 2020/21 BRA parameter, similar to Section IV.C). Starting from this base assumption, we then explore the impact of potential future conditions with different prices differences between LDAs and parent zones.

In the 2020/21 BRA parameters, most LDAs have market entry prices below their parents and our simulated results show that LDAs easily meet the 1-in-25 reliability standard. However, we caution that LDA market entry prices may not remain below parent levels in a long-run equilibrium where increased entry reduces E&AS offsets and increases the costs that must be recovered in the capacity market. We estimate that when the market entry price is 5% higher in each LDA compared to its parent (and the administrative Net CONE parameter is also 5% higher), five of the fourteen LDAs fail to meet the 1-in-25 standard. To address the greater risk of locational reliability challenges, we recommend a higher price cap for the locational demand curves at 1.7 × Net CONE. This results in a curve with a similar price cap to our recommended system level curve (curve **E** in Figure ES-1), but without the 1% left-shift. We also recommend a minimum LDA demand curve width at 25% of the Capacity Emergency Transfer Limit (CETL). These two adjustments combined reduce the locational reliability risks and result in each of the fourteen LDAs meeting the 1-in-25 LOLE target.

A. Summary of Locational Reliability Requirement

PJM's local resource adequacy requirements are set based on a 1-in-25 or 0.04 *conditional* LOLE standard. The locational standard reflects the total amount of local supply plus imports that would be needed to meet 0.04 LOLE under the conditional assumption that imports are fully available at the CETL import limit.[78] Taken at face value, the local standard would appear to

[78] See PJM (2017g), Section 2.2.

suggest that an import-constrained LDA would be more reliable than the system as a whole, with local load shed events only once every 25 years compared to once every 10 years at the system level. This is not the case, however, because the local 1-in-25 reliability standard does not include all of the reliability events that an LDA would be expected to experience (the LDA is also subject to loss of load in the event of system-wide shortages). Instead, the local 1-in-25 is a conditional LOLE standard, measuring local reliability events that would occur if the LDA could always import up to the CETL limit (*i.e.*, assuming no outages at the system level or parent LDA level.)

An additional complexity in the local standard is that the realized reliability at the LDA level depends on the level of overlap between the local outage events and the system-wide and parent LDA outage events. For a first-level LDA, the realized LOLE could be as low as 0.10 or as high as 0.14, if the events occur at exactly the same time or at entirely different times from the system-wide outage events. For a fourth-level LDA, realized LOLE could be as low as 0.1 or as high as 0.26 in the unlikely event that all outage events occur at different times, as well as in its parent LDAs and RTO. Thus, the reliability standard as currently implemented could result in very different LOLEs at different locations within PJM's footprint, with the estimated reliability not reported after considering this additive effect.

Beyond these potential discrepancies in LOLEs by LDA, there may be larger discrepancies in realized reliability among LDAs based on the definition of LOLE itself. While LOLE is a widely-used metric for determining reliability standards, it is relatively less meaningful than some alternatives. Because LOLE counts only load shed events, but not their depth or duration, it will treat a small, short event and a large, widespread event with equal importance. The metric may also have very different meanings at different LDA levels, since the magnitude of outages is not normalized by the LDA size. As we discussed in our 2014 Review, PJM could consider switching to a locational reliability requirement based on Expected Unserved Energy to address this shortcoming.

B. Qualitative Review of Locational Curves

In this Section, we qualitatively evaluate the VRR curve as applied at the local level, to develop intuition around the likely performance concerns and locational price efficiency, before estimating its performance quantitatively in subsequent Sections. In developing this evaluation, we: (1) review the design objectives at the local level, specifically the Net CONE parameters; and (2) review the price cap and shape of the demand curves at the local level.

1. LDA Net CONE

In both our Base Case and with updated CC and CT Net CONE, some LDAs have lower Net CONE than their parent zones. However, long-run average LDA Net CONE may not remain lower than parent Net CONE.[79] If LDA Net CONE is temporarily lower than parent Net CONE, the LDA would attract new supply because of the attractiveness of a more economic investment opportunity (with lower Net CONE but equal or higher capacity prices). This additional supply would tend to reduce local energy prices and possibly raise local gas prices, eroding the E&AS margin in the LDA and ultimately increasing LDA Net CONE. Since capacity prices in the LDA have a soft floor at the parent price, supply will likely continue to enter in the LDA until LDA Net CONE reaches or exceeds parent Net CONE. If long-run average LDA Net CONE rises above the parent Net CONE, PJM's LDAs would remain import-constrained in the long-run equilibrium. If instead the E&AS margin does not erode, lower Net CONE values could persist in the long-run equilibrium. In this case, supply would continue to enter the LDA until it ceases to be import constrained in the long-run equilibrium.

The case where LDAs have higher Net CONE than their parents is more important, since that is the only case where the local VRR curve will impact price and quantity outcomes in the long term. VRR curves should be designed to perform well in this case. Our locational simulated performance in the remainder of this section focuses on cases where each LDA is import-constrained, with a Net CONE higher than the parent LDA. In these cases, our results suggest that having a higher price cap in the LDAs will improve reliability to meet 1-in-25 LOLE target.

2. Locational Curve Price Cap and Shape

Similar to the system-level comparison of reliability metrics and the VRR curve from Section IV.B, we compare the local VRR curves to the LDA conditional LOLE curves as shown in Figure 21. We place particular emphasis on the shape of the curve at quantities below the reliability requirement, and observe that prices will reach the cap before rapidly increasing LOLE resulting in very low reliability outcomes. The LDA VRR curves have the same shape as PJM's current system VRR curve. Based on the current VRR curve, prices would reach the cap at conditional LOLE values of approximately 0.042 to 0.045 (reliability index of 1-in-24 to 1-in-22, compared to a standard of 1-in-25) depending on the LDA.

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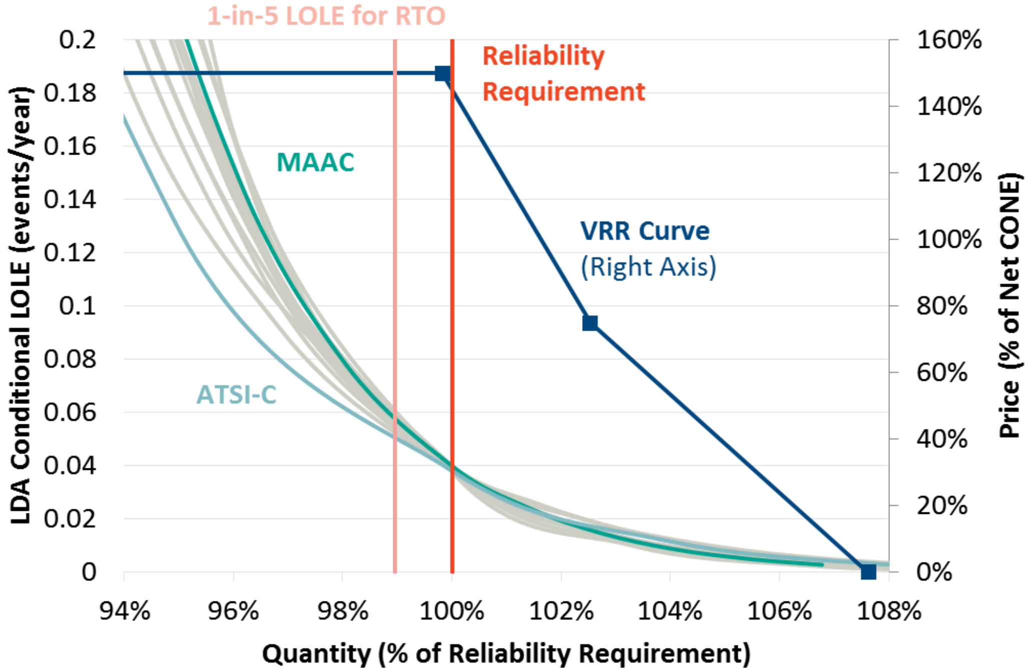
[79] In our third triennial review, we recommended imposing a minimum on LDA Net CONE at the parent level to mitigate the risk of underestimating locational Net CONE and reducing reliability. As we noted in the previous analysis, many of the smaller LDAs lack a local CONE estimate and have a small sample of new generation data points to inform Gross CONE and E&AS margins. It is therefore more likely that Gross CONE estimates in those LDAs do not accurately represent local siting and permitting costs and that Net CONE estimates may reflect inaccurate E&AS margins. As discussed above, under-procurement in the smaller LDAs reduces reliability more severely than it would at the system level. The FERC rejected PJM's proposal in 2014, citing a lack of firm basis to support the proposal. FERC stated "this [Net CONE floor at parent level] proposal could operate to disconnect costs and/or revenues from the areas to which they can be attributed, particularly given that generators in a congested area may receive higher energy market revenues than in uncongested areas, thereby warranting a larger EAS Offset in the congested area." See FERC (2014), Section V.E.4.

Figure 21
Local VRR Curve Compared to Conditional Loss of Load Event
(Without Adding Parent-LDA or System-Wide LOLE Events)



Sources and Notes:

Current VRR Curve reflects the system VRR curve in the 2020/21 PJM Planning Parameters. See PJM (2017c).

The Conditional LOLE curves reflect the relationship between total quantity and reliability for each of the 14 non-RTO LDAs.

In principle, PJM could adopt zonal demand curves proportional to marginal reliability value to align prices with relative reliability value, to mitigate price volatility, and to offer more graduated price separation as zones become short. We do not recommend this approach, however, as PJM's current reliability modeling may understate reliability risks in the zones, especially for correlated outages. To allow for marginal reliability demand curves, PJM could develop its reliability modeling to simultaneously assess system and locational reliability risks and account for correlations. The refined reliability modeling approach would account for the greater reliability value of LDA-internal resources relative to resources imported from the parent zone in import-constrained LDAs.[80]

3. Locational Curve Width

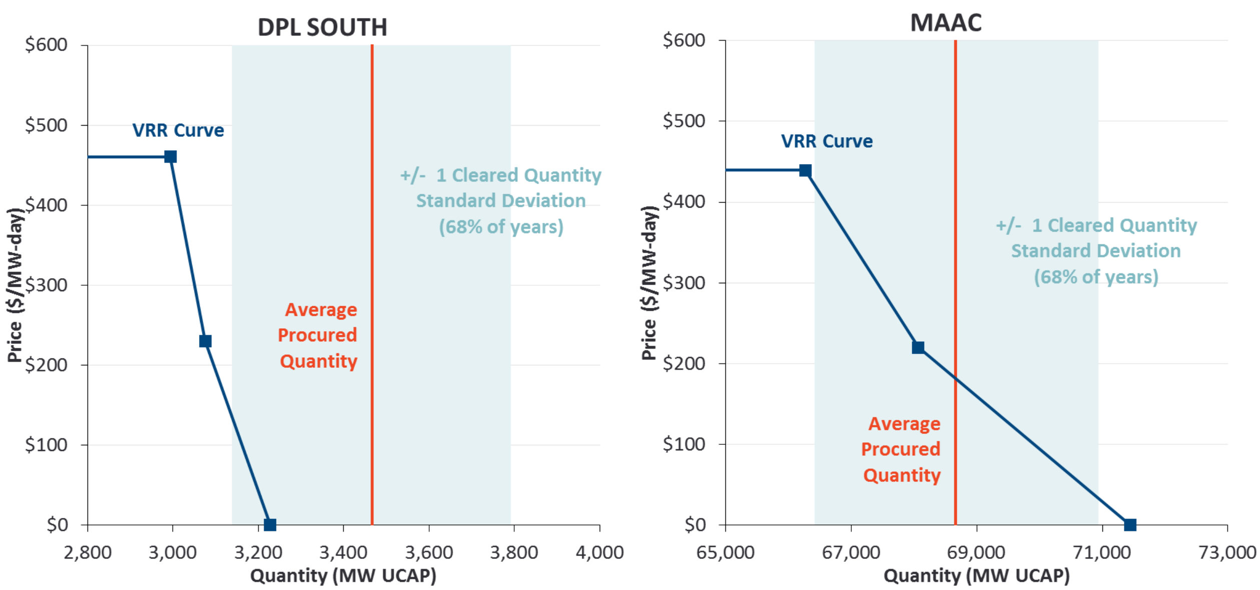
We also examine the width of the locational VRR curves compared to expected year-to-year fluctuation to the cleared supply (including imports) at the local level. In Figure 22, we show the

80 We have a more detailed discussion on clearing mechanics for locational reliability value in our 2014 report, see Pfeifenberger (2014).

width of the VRR curve compared to the standard deviation in cleared supply fluctuations for the largest and smallest LDAs (MAAC and DPL-South respectively), and for all LDAs in Table 14.

We observe that the year-to-year fluctuations to cleared supply at the local level are large relative to the width of the VRR curves. This is particularly true for the smallest LDAs and the LDAs with the greatest level of import-dependence. In these locations, small increases or decreases in supply the size of a single generation plant could result in price changes from the cap to the floor. In fact, in the smallest LDA of DPL-South, a single 700 MW power plant has a size approximately three times the width of the entire VRR curve. For highly import-dependent LDAs, changes to the CETL introduce a substantial source of volatility. For example, in the import-dependent LDA of BGE, CETL would represent 76% of the reliability requirement whenever the LDA is import-constrained. A drop in the 2020/21 CETL by our estimated 15% standard deviation would correspond to a 940 MW drop in total supply, or approximately 150% of the width of the entire VRR curve.

Figure 22
Locational VRR Curve Width Compared to Expected Cleared Supply Fluctuations



Sources and Notes:

Current VRR Curve reflects the DPL-South and MAAC VRR curves in the 2020/21 PJM Planning Parameters, adjusted for the parent Net CONE floor detailed in Section 1. See PJM (2017c).

The range of expected cleared supply fluctuations are based on simulated outcomes of for DPL-S and MAAC in our Base Case run.

The standard deviation of simulated cleared supply fluctuations is 327 MW for DPL-S and 2,270 MW for MAAC.

The average procured quantities are using results from the +5% LDA Net CONE case.

Table 14
Locational VRR Curve Width Compared to Cleared Supply Fluctuation Sizes

LDA	VRR Curve Width *(MW)* [1]	Cleared Supply Fluctuations St. Dev. *(MW)* [2]	Supply Fluctuations as Percent of Curve Width *(%)* [3]
RTO	13,076	2,331	18%
MAAC	5,178	2,269	44%
EMAAC	2,880	1,882	65%
SWMAAC	1,208	1,591	132%
ATSI	1,218	1,677	138%
PSEG	920	1,280	139%
PEPCO	622	1,250	201%
PS-N	470	707	150%
ATSI-C	457	873	191%
DPL-S	234	327	140%
COMED	2,045	1,319	64%
BGE	634	946	149%
PPL	767	1,270	166%
DAYTON	314	538	171%
DEOK	585	802	137%

Notes:
[1]: Distance from 2020/21 VRR Curve Point "a" to Point "c", See PJM (2017c).
[2]: Equal to simulated cleared supply fluctuations from Base Case.
[3]: [2]/[1].

While these net fluctuation estimates indicate substantial potential for price volatility and reliability concerns in smaller and more import-constrained LDAs, we caution that this simplified comparison does not consider the price volatility-mitigating effects of the nested LDA structure. The potential for low-price outcomes are substantially mitigated by the fact that LDAs' prices cannot fall below the parent LDA or RTO prices and so are protected from downside price outcomes to some extent. Our simulation analysis presented in Section V.C accounts for this effect.

However, the reverse is not true in that high-price and low-reliability outcomes are not mitigated under this structure and therefore can result in periodic price spikes in excess of what would be seen in the broader RTO or larger LDAs. Mitigating the potential for low-reliability outcomes at the LDA level could be addressed in a number of ways. Low reliability could both be mitigated by stretching the curve rightward, with the lower-priced parts of the curve shifting the furthest to the right. This would serve to right-shift the entire distribution of reserve margin outcomes. Alternatively, the price cap in the LDAs could be increased relative to the system level in order to increase supply during shortage conditions.

Changes to the locational VRR curve are not the only way to address these concerns. Similar to our 2014 Review, we recommend that PJM continue to review options for increasing the predictability and stability of its administrative CETL estimates. Reducing volatility in this parameter could substantially reduce the likelihood and magnitude of price spikes in LDAs. However, we caution that approaches to reducing CETL volatility should be focused on reducing volatility within the bands of administrative uncertainty, but should not prevent CETL from changing with physical changes to the transmission system.[81] For example, one reason for administrative uncertainty in CETL is the impact of modeling assumptions, such as load flow cases; with reasonable differences in modeling assumptions resulting in power flowing over different transmission paths. The stability of CETL, therefore, might be improved if PJM were able to identify primary modeling uncertainties and calculating CETL as a midpoint among different estimated values.

Other options for addressing volatility impacts of CETL include changing the representation of locational constraints in RPM. One of those options would be to explore a more generalized approach to modeling locational constraints in RPM beyond just import-constrained, nested LDAs with a single import limit. A final option for mitigating price volatility in LDAs would be to revise the RPM auction clearing mechanics according to locational reliability, as discussed in the Section V.D.

C. Simulated Performance of System Curves Applied Locally

In this section, we present simulation analyses of the performance of the current VRR curve applied locally. Results presented in this section do *not* reflect our recommended left-shift to the VRR curve if PJM adopts CC Net CONE. We present the locational results under Base Case assumptions, as well as sensitivities to the Base Case assumptions and administrative errors in Net CONE. In our Base Case we find that the current VRR curve is likely to meet the 0.04 LOLE target on average across all LDAs. To test the performance of this curve, we evaluate a non-stress scenario in which each LDA has Net CONE at a moderate 5% above the parent LDA Net CONE, which provides an indicator of performance under relatively typical conditions when LDA import limits are binding. We find that under this scenario the current VRR curve is not likely to meet the 0.04 LOLE target on average across a handful of the LDAs in this non-stress scenario. We also test a stress scenario in which each of the smallest level LDAs have Net CONE at 20% above the parent LDA. We find that the current VRR curve is likely to meet the 0.04 LOLE target on average across larger LDAs but not meet the target across the smaller, import-constrained LDAs in this stress scenario.

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81 See our 2011 study, Pfeifenberger (2011), for a more comprehensive discussion of uncertainty in CETL and options for addressing the volatility in this parameter.

1. Performance under Base Case Assumptions

Table 15 summarizes the simulated performance of the current VRR curve under our Base Case assumptions, with revised price and quantity metrics relevant for comparing performance at the LDA level. Under our Base Case assumptions, the current VRR curve is likely to reach reliability targets on average across all LDAs. While assessing the performance of the VRR curve under Base Case assumptions is necessary, the case where LDAs have a higher Net CONE than the parent area is more important, since that is the only case where the local VRR curve will impact price and quantity outcomes in the long-term as discussed in earlier. Thus, in the remainder of our analysis we analyze sensitivities to our Base Case assumptions for cases where each LDA is import-constrained, with a higher Net CONE than the parent LDA.

Table 15
Performance of VRR Curve in LDAs under Base Case Assumptions
Assumes Market Entry Occurs at the Price Corresponding to Administrative Net CONE

	Price and Procurement Costs					Reliability					
	Average Price (= Market Entry Price) *($/MW-d)*	Standard Deviation of Price *($/MW-d)*	Frequency at Cap *(%)*	Frequency of Price Separation *(%)*	Average Cost (P × Q) *($mil)*	Average LOLE *(Ev/Yr)*	Average LOLE (Additive) *(Ev/Yr)*	Average Quantity as % of Rel. Req. *(%)*	Standard Deviation as % of Rel. Req. *(%)*	Frequency Below Rel. Req. *(%)*	Frequency Below 1-in-5 *(%)*
Current VRR Curve											
MAAC	$293	$87	10%	0%	$6,638	0.000	0.054	115%	3%	0%	0%
EMAAC	$293	$87	10%	0%	$3,618	0.001	0.055	115%	5%	0%	0%
SWMAAC	$293	$87	10%	0%	$1,518	0.000	0.054	153%	11%	0%	0%
ATSI	$294	$88	11%	1%	$1,483	0.001	0.054	128%	11%	1%	0%
PSEG	$307	$93	7%	11%	$1,179	0.022	0.077	116%	11%	7%	5%
PEPCO	$293	$87	10%	0%	$742	0.000	0.054	148%	16%	0%	0%
PS-N	$307	$93	7%	1%	$603	0.001	0.078	135%	12%	0%	0%
ATSI-C	$294	$88	11%	0%	$497	0.000	0.054	169%	16%	0%	0%
DPL-S	$293	$87	10%	0%	$264	0.000	0.055	232%	13%	0%	0%
COMED	$330	$105	0%	35%	$2,938	0.032	0.085	105%	5%	14%	10%
BGE	$293	$87	10%	0%	$777	0.000	0.053	148%	12%	0%	0%
PPL	$293	$87	10%	1%	$838	0.000	0.054	138%	13%	0%	0%
DAY	$293	$87	10%	0%	$391	0.000	0.053	198%	15%	0%	0%
DEOK	$293	$87	10%	0%	$632	0.000	0.053	156%	12%	0%	0%

Notes:
Price and cost results may be affected by a +/- 0.2% convergence error in Net CONE in this and subsequent tables.
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.
Results assume that the market entry price is equal to administrative Net CONE.

2. Performance with Net CONE Higher than Parent

We report here the simulated performance of the current VRR curve under two different assumptions regarding local Net CONE values. In Table 16, we present results if assuming that local Net CONE is 5% higher than the parent Net CONE in each successive import-constrained LDA (with the MAAC value fixed at its Base Case value). This case provides a reasonable basis for evaluating the performance of the VRR Curve under typical conditions, where more import-constrained locations do show higher net investment costs but are only modestly higher than elsewhere.

In Table 16, we show a more stressed case in which Net CONE is 5% higher in each LDA (as in the first case) but the lowest-level LDAs (PS-North, DPL-South, PepCo, BGE, PPL, ATSI-C, ComEd, Dayton, and DEOK) have a substantially higher Net CONE that is 20% above the parent LDA value. For example, PS-North would have a 39% higher Net CONE than the Rest of RTO. This provides an illustration of the VRR curve performance in locations with much higher investment costs associated with siting difficulties, environmental restrictions, or lack of available gas and electric infrastructure. In both cases, we assume that the administrative Net CONE is accurate and equal to the actual price at which developers will enter the market.

Under the 5% higher case, we observe that the current VRR curve falls short of the local resource adequacy requirement of 1-in-25 (or 0.04 LOLE) in five of the fourteen LDAs. For ease of reference, we highlight the locations that fall short of these thresholds in all tables reported in this and the following sections.

In the more stressed case reflected in Table 17, we see that all of the locations with Net CONE 20% above the parent all fail to meet the reliability objective. The poorest-performing LDAs in this case are some of the most import-dependent locations, such as PepCo and Dayton.

These results demonstrate that the current VRR curve will achieve local reliability objectives in some of the LDAs but fail to do so in highly import-dependent LDAs. We discuss our recommendations for locational curves to prevent the susceptibility of low reliability in Section V.D.

Table 16

VRR Curve's Performance with Net CONE always 5% Higher than Parent Net CONE

Assumes Market Entry Occurs at the Price Corresponding to Administrative Net CONE

	Price and Procurement Costs					Reliability					
	Average Price (= Market Entry Price)	Standard Deviation of Price	Frequency at Cap	Frequency of Price Separation	Average Cost (P × Q)	Average LOLE	Average LOLE (Additive)	Average Quantity as % of Rel. Req.	Standard Deviation as % of Rel. Req.	Frequency Below Rel. Req.	Frequency Below 1-in-5
	($/MW-d)	*($/MW-d)*	*(%)*	*(%)*	*($mil)*	*(Ev/Yr)*	*(Ev/Yr)*	*(%)*	*(%)*	*(%)*	*(%)*
Current VRR Curve											
MAAC	$293	$92	12%	31%	$7,064	0.022	0.077	103%	3%	13%	7%
EMAAC	$308	$98	8%	17%	$3,947	0.014	0.091	107%	5%	8%	4%
SWMAAC	$308	$99	8%	13%	$1,642	0.038	0.115	114%	10%	8%	6%
ATSI	$293	$90	7%	13%	$1,473	0.035	0.090	115%	11%	7%	6%
PSEG	$323	$103	6%	10%	$1,306	0.019	0.110	117%	11%	6%	5%
PEPCO	$323	$106	7%	10%	$823	0.049	0.164	122%	16%	8%	6%
PS-N	$339	$110	8%	13%	$676	0.038	0.148	116%	12%	8%	7%
ATSI-C	$308	$99	7%	11%	$522	0.039	0.129	121%	15%	7%	6%
DPL-S	$323	$104	6%	11%	$303	0.014	0.105	116%	11%	7%	4%
COMED	$330	$112	0%	43%	$2,943	0.040	0.096	104%	5%	18%	12%
BGE	$323	$105	0%	10%	$870	0.023	0.116	117%	12%	6%	4%
PPL	$308	$98	8%	11%	$897	0.097	0.174	117%	13%	7%	6%
DAY	$293	$92	19%	13%	$381	0.105	0.160	117%	13%	9%	7%
DEOK	$293	$93	19%	15%	$631	0.049	0.104	115%	11%	9%	7%

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.
Results assume that the market entry price is equal to administrative Net CONE.

Table 17
Performance with LDA Net CONE 5% Higher than Parent or 20% Higher in
(Lowest Level LDAs of PS-North, DPL-South, PepCo, BGE, PPL, ATSI-C, ComEd, Dayton, and DEOK)
Assumes Market Entry Occurs at the Price Corresponding to Administrative Net CONE

	Price and Procurement Costs					Reliability						
	Average Price (= Market Entry Price)	Standard Deviation of Price	Frequency at Cap	Frequency of Price Separation	Average Cost (P × Q)	Average LOLE	Average LOLE (Additive)	Average Quantity as % of Rel. Req.	Standard Deviation as % of Rel. Req.	Frequency Below Rel. Req.	Frequency Below 1-in-5
	($/MW-d)	*($/MW-d)*	*(%)*	*(%)*	*($mil)*	*(Ev/Yr)*	*(Ev/Yr)*	*(%)*	*(%)*	*(%)*	*(%)*
Current VRR Curve											
MAAC	$293	$92	12%	27%	$7,218	0.020	0.079	104%	3%	12%	6%
EMAAC	$308	$98	8%	16%	$3,997	0.014	0.093	107%	5%	9%	5%
SWMAAC	$308	$100	8%	14%	$1,691	0.050	0.129	113%	10%	8%	7%
ATSI	$293	$91	7%	12%	$1,482	0.036	0.095	115%	11%	7%	6%
PSEG	$323	$104	7%	11%	$1,335	0.021	0.113	116%	11%	8%	5%
PEPCO	$369	$134	22%	29%	$841	0.358	0.486	111%	15%	22%	19%
PS-N	$388	$139	19%	31%	$717	0.127	0.240	109%	12%	21%	18%
ATSI-C	$352	$127	23%	30%	$544	0.156	0.251	111%	15%	23%	19%
DPL-S	$369	$133	19%	31%	$330	0.095	0.188	108%	10%	20%	17%
COMED	$335	$114	0%	45%	$2,988	0.041	0.100	104%	5%	19%	13%
BGE	$369	$135	0%	31%	$912	0.216	0.325	109%	12%	22%	19%
PPL	$352	$125	0%	31%	$977	0.412	0.491	109%	12%	21%	18%
DAY	$335	$119	0%	33%	$397	0.474	0.533	109%	13%	22%	19%
DEOK	$335	$120	0%	32%	$681	0.178	0.236	108%	11%	23%	20%

Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

3. Sensitivity to Primary Modeling Uncertainties

Similar to our analysis of the system-wide VRR curve detailed in Section IV.C, we test the robustness of our conclusions using a sensitivity analysis on our Base Case modeling assumptions for the LDA VRR curves. We first test the sensitivity of our results if all fluctuations are 33% larger or 33% smaller than their Base Case values. We then evaluate results under an alternate assumption with no CETL fluctuations.

In Table 18 we present the results after introducing 33% larger fluctuations, 33% smaller fluctuations, and eliminating all CETL fluctuations. With larger or smaller fluctuations, results are consistent with our expectations. We see that price volatility increases and reliability decreases with 33% larger fluctuations (eleven of the fourteen LDAs do not reach the 0.04 LOLE standard), and that the reverse is true with smaller fluctuations (almost every LDA meets the 0.04 LOLE standard). Eliminating fluctuations to CETL also improves reliability and the 0.04 LOLE target is met for nearly all LDAs with the current VRR curve (ComEd has a 0.041 average LOLE, slightly worse than the target).

Table 18

Performance of VRR Curve in LDAs under Fluctuations and CETL Sensitivities

(LDA Net CONE 5% Higher than Parent)

All Cases Assume Market Entry Occurs at the Price Corresponding to Administrative Net CONE

	Price and Procurement Costs					Reliability					
	Average Price (= Market Entry Price)	Standard Deviation of Price	Frequency at Cap	Frequency of Price Separation	Average Cost (P × Q)	Average LOLE	Average LOLE (Additive)	Average Quantity as % of Rel. Req.	Standard Deviation as % of Rel. Req.	Frequency Below Rel. Req.	Frequency Below 1-in-5
	($/MW-d)	*($/MW-d)*	*(%)*	*(%)*	*($mil)*	*(Ev/Yr)*	*(Ev/Yr)*	*(%)*	*(%)*	*(%)*	*(%)*
33% Increase in Fluctuation Size											
MAAC	$293	$102	13%	27%	$7,073	0.027	0.122	104%	4%	14%	9%
EMAAC	$308	$108	10%	17%	$3,936	0.017	0.139	108%	7%	10%	8%
SWMAAC	$308	$108	8%	13%	$1,640	0.098	0.220	118%	14%	9%	7%
ATSI	$293	$102	9%	14%	$1,467	0.126	0.221	118%	14%	9%	8%
PSEG	$323	$113	8%	10%	$1,302	0.042	0.181	121%	15%	8%	6%
PEPCO	$323	$115	7%	10%	$820	0.106	0.325	130%	21%	8%	6%
PS-N	$339	$120	8%	13%	$671	0.068	0.249	120%	16%	9%	8%
ATSI-C	$308	$109	9%	11%	$520	0.068	0.289	126%	20%	9%	7%
DPL-S	$323	$114	7%	11%	$302	0.020	0.159	123%	16%	7%	6%
COMED	$330	$121	0%	42%	$2,928	0.069	0.164	105%	7%	22%	16%
BGE	$323	$114	0%	10%	$866	0.066	0.259	122%	16%	7%	5%
PPL	$308	$106	8%	9%	$894	0.186	0.308	124%	17%	6%	6%
DAY	$293	$100	22%	11%	$382	0.192	0.287	124%	18%	8%	7%
DEOK	$293	$102	22%	12%	$630	0.080	0.175	120%	15%	9%	7%
33% Decrease in Fluctuation Size											
MAAC	$293	$78	6%	25%	$7,030	0.017	0.055	103%	2%	7%	1%
EMAAC	$308	$84	6%	18%	$3,931	0.014	0.069	105%	3%	7%	2%
SWMAAC	$308	$86	7%	14%	$1,631	0.016	0.071	109%	7%	7%	5%
ATSI	$293	$77	6%	10%	$1,474	0.012	0.050	112%	7%	6%	4%
PSEG	$323	$92	6%	11%	$1,297	0.011	0.080	111%	8%	6%	4%
PEPCO	$323	$94	6%	10%	$823	0.018	0.089	115%	10%	7%	5%
PS-N	$339	$98	6%	12%	$680	0.020	0.100	112%	8%	7%	6%
ATSI-C	$308	$85	6%	10%	$522	0.022	0.072	116%	11%	6%	4%
DPL-S	$323	$92	7%	14%	$303	0.012	0.081	110%	7%	7%	4%
COMED	$330	$97	0%	46%	$2,960	0.028	0.065	103%	3%	14%	9%
BGE	$323	$93	0%	12%	$866	0.014	0.068	111%	8%	7%	4%
PPL	$308	$84	7%	12%	$898	0.021	0.076	113%	9%	5%	4%
DAY	$293	$79	13%	14%	$380	0.060	0.098	114%	10%	7%	5%
DEOK	$293	$80	13%	14%	$633	0.018	0.055	111%	8%	8%	6%
Zero CETL Shocks											
MAAC	$293	$92	11%	25%	$6,988	0.019	0.076	104%	3%	12%	5%
EMAAC	$308	$98	8%	22%	$3,936	0.016	0.092	105%	4%	9%	4%
SWMAAC	$308	$99	8%	18%	$1,611	0.015	0.090	106%	4%	9%	4%
ATSI	$293	$89	6%	17%	$1,469	0.016	0.073	106%	4%	6%	3%
PSEG	$323	$101	6%	20%	$1,293	0.015	0.107	105%	4%	6%	3%
PEPCO	$323	$102	5%	17%	$831	0.011	0.102	106%	4%	6%	2%
PS-N	$339	$106	7%	18%	$682	0.026	0.133	106%	5%	7%	6%
ATSI-C	$308	$96	8%	18%	$530	0.015	0.088	105%	4%	9%	3%
DPL-S	$323	$104	5%	16%	$303	0.015	0.107	107%	5%	6%	3%
COMED	$330	$112	0%	46%	$2,947	0.041	0.098	103%	4%	19%	13%
BGE	$323	$101	0%	16%	$875	0.011	0.082	106%	4%	4%	1%
PPL	$308	$95	8%	15%	$899	0.013	0.089	109%	6%	4%	3%
DAY	$293	$87	19%	13%	$384	0.009	0.066	108%	5%	4%	2%
DEOK	$293	$90	19%	18%	$635	0.013	0.069	106%	4%	7%	4%

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

4. Sensitivity to Administrative Errors in Net CONE

The reliability risks introduced by the potential for errors in Net CONE are even more important at the LDA level than on a system-wide basis, although we view these as important risks in both cases. We view these risks as more important at the LDA level partly because we believe the potential for errors in Net CONE is greater at the LDA level, particularly for the smallest LDAs for which there is no location-specific Gross CONE or E&AS estimate. Adopting more location-specific Net CONE estimates will reduce these risks, but small LDAs will still be at greater risk for Net CONE estimation error. This is because the smallest LDAs are the most prone to idiosyncratic siting, environmental, or infrastructure limitations that do not apply in the larger CONE Area. Further, these locations are unlikely to have a substantial number of units similar to the reference unit, and so calibrating E&AS to plant actual data will not be possible.

Similar to the system level, over-estimating Net CONE results in improved reliability and increased price volatility while under-estimating Net CONE results in significantly worse reliability and lower price volatility because of a lower price cap. Table 19 reports the results for each LDA under these sensitivities and shows nearly all LDAs do not achieve the 0.04 conditional LOLE standard when Net CONE is under-estimated (EMAAC is the only LDA that meets the 0.04 LOLE target). This suggests again that the administrative Net CONE estimation has significant implications for the reliability of the VRR curve due to its impact on the price cap.

Table 19
VRR Curve Performance with 20% Over- and Under-Estimate in Net CONE
(LDA Net CONE 5% Higher than Parent)
All Cases Assume Market Entry Occurs at the Price Corresponding to Administrative Net CONE

	Price and Procurement Costs					Reliability					
	Average Price (= Market Entry Price)	Standard Deviation of Price	Frequency at Cap	Frequency of Price Separation	Average Cost (P × Q)	Average LOLE	Average LOLE (Additive)	Average Quantity as % of Rel. Req.	Standard Deviation as % of Rel. Req.	Frequency Below Rel. Req.	Frequency Below 1-in-5
	($/MW-d)	*($/MW-d)*	*(%)*	*(%)*	*($mil)*	*(Ev/Yr)*	*(Ev/Yr)*	*(%)*	*(%)*	*(%)*	*(%)*
20% Over-Estimate in Net CONE											
MAAC	$293	$100	4%	19%	$7,097	0.012	0.050	105%	3%	4%	3%
EMAAC	$308	$112	4%	15%	$3,945	0.009	0.059	108%	5%	4%	2%
SWMAAC	$308	$113	5%	11%	$1,641	0.027	0.077	117%	11%	5%	4%
ATSI	$293	$101	4%	9%	$1,484	0.016	0.053	118%	11%	4%	3%
PSEG	$323	$124	5%	9%	$1,299	0.019	0.078	119%	12%	5%	4%
PEPCO	$323	$127	5%	8%	$819	0.028	0.105	125%	16%	5%	4%
PS-N	$339	$138	6%	10%	$674	0.031	0.109	119%	13%	6%	5%
ATSI-C	$308	$115	5%	8%	$521	0.025	0.079	124%	16%	5%	4%
DPL-S	$323	$128	6%	9%	$299	0.064	0.123	140%	22%	6%	5%
COMED	$330	$128	0%	36%	$2,955	0.021	0.059	106%	5%	9%	6%
BGE	$323	$125	0%	8%	$863	0.017	0.082	119%	12%	4%	4%
PPL	$308	$110	5%	7%	$897	0.035	0.084	123%	13%	3%	3%
DAY	$293	$104	9%	10%	$385	0.074	0.112	121%	14%	6%	4%
DEOK	$293	$106	9%	10%	$632	0.028	0.066	117%	12%	5%	4%
20% Under-Estimate in Net CONE											
MAAC	$293	$68	31%	43%	$6,989	0.057	0.258	101%	4%	34%	20%
EMAAC	$308	$69	22%	30%	$3,927	0.039	0.298	104%	5%	23%	16%
SWMAAC	$308	$68	20%	23%	$1,621	0.225	0.484	108%	10%	20%	16%
ATSI	$293	$66	21%	24%	$1,452	0.230	0.432	108%	11%	22%	18%
PSEG	$323	$70	18%	22%	$1,289	0.098	0.395	110%	11%	19%	15%
PEPCO	$323	$70	17%	20%	$813	0.252	0.735	114%	16%	18%	15%
PS-N	$339	$70	18%	23%	$670	0.123	0.518	110%	12%	19%	17%
ATSI-C	$308	$67	20%	24%	$522	0.123	0.554	112%	15%	20%	16%
DPL-S	$323	$70	20%	23%	$302	0.097	0.395	111%	12%	20%	17%
COMED	$330	$75	0%	60%	$2,920	0.140	0.342	101%	5%	42%	35%
BGE	$323	$71	0%	22%	$862	0.140	0.567	111%	12%	19%	15%
PPL	$308	$67	20%	18%	$900	0.284	0.542	113%	13%	15%	13%
DAY	$293	$65	51%	23%	$376	0.424	0.626	112%	13%	19%	16%
DEOK	$293	$67	51%	23%	$628	0.158	0.360	110%	11%	21%	17%

Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

D. Recommendations for Locational VRR Curves

PJM's LDAs face different reliability challenges than the system. Assuming that administrative Net CONE and the market entry price are equal to each other (and using the 2020/21 BRA parameters, similar to Section IV.C), local VRR curves perform well.[82] However, under potential future conditions where market entry prices in the LDAs exceed those in the parent, we identified several concerns. Under these conditions, the smaller size of LDAs relative to fluctuations in local net supply make it more difficult to attract investment and lead to reliability challenges.

Our simulations demonstrate these risks and show that the existing VRR curves would often not achieve the 1-in-25 conditional target if LDA Net CONE were greater than parent Net CONE, with the greatest susceptibility in the most import-dependent LDAs and LDAs with Net CONE substantially above the parent LDA Net CONE. To ensure more robust performance from a reliability perspective, provide more price stability, and produce prices that are more reflective of local reliability value, we recommend that PJM and stakeholders consider the following changes to local VRR curves:

1. **Impose a minimum curve width equal to 25% of CETL.** We find that the current VRR curve would not achieve the local reliability objective in a realistic stress scenario with LDA Net CONE substantially above the parent level. Performance is worst in the smallest, most import-dependent zones. To address this gap, we find that applying a minimum curve width based on CETL to be a targeted and effective way to improve performance.[83] See Table 20. This minimum curve width could be applied to local curves of the same shape as any of the candidate system curves from Figure ES-1.
2. **Ensure the LDA price cap is at least 1.7 × Net CONE.** We find that a price cap of at least 1.7 × Net CONE substantially improves simulated reliability outcomes in LDAs because it introduces stronger price signals when supplies become scarce. The prospect of higher prices during low reliability outcomes provides greater incentives for suppliers to locate there rather than in the parent LDA. If PJM adopts our recommended system curve based on CC Net CONE, with a 1% left-shift and 70% Gross CONE price cap (curve **E** in Figure ES-1), the price cap will already be approximately 1.8 × Net CONE. No further change is needed if this curve is applied at the local level. See Table 20.

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82 If PJM adopted a VRR curve anchored on a Net CONE value considerably greater than the market entry price, such as curve **A** or curve **B** in Figure ES-1, the LDAs would become even more reliable.

83 We have not performed a detailed assessment of the locational performance of a 1% left-shifted curve. It is possible that the left shift would slightly reduce reliability in the LDAs and require a slightly wider curve to accommodate.

Table 20

Performance with LDA Net CONE 5% Higher than Parent under Recommended LDA Curves

All Cases Assume Market Entry Occurs at the Price Corresponding to Administrative Net CONE

	Price and Procurement Costs					Reliability					
	Average Price (= Market Entry Price)	Standard Deviation of Price	Frequency at Cap	Frequency of Price Separation	Average Cost (P × Q)	Average LOLE	Average LOLE (Additive)	Average Quantity as % of Rel. Req.	Standard Deviation as % of Rel. Req.	Frequency Below Rel. Req.	Frequency Below 1-in-5
	($/MW-d)	*($/MW-d)*	*(%)*	*(%)*	*($mil)*	*(Ev/Yr)*	*(Ev/Yr)*	*(%)*	*(%)*	*(%)*	*(%)*
Net CONE 5% Higher than Parent, Current VRR Curve											
PEPCO	$323	$106	7%	10%	$823	0.049	0.164	122%	16%	8%	6%
COMED	$330	$112	0%	43%	$2,943	0.040	0.096	104%	5%	18%	12%
PPL	$308	$98	8%	11%	$897	0.097	0.174	117%	13%	7%	6%
DAY	$293	$92	19%	13%	$381	0.105	0.160	117%	13%	9%	7%
DEOK	$293	$93	19%	15%	$631	0.049	0.104	115%	11%	9%	7%
Net CONE 5% Higher than Parent, LDA Width at Least 25% of CETL											
PEPCO	$323	$101	5%	12%	$827	0.026	0.143	125%	16%	5%	5%
COMED	$330	$110	0%	40%	$2,940	0.037	0.108	104%	5%	17%	11%
PPL	$308	$95	7%	14%	$895	0.063	0.151	119%	13%	5%	5%
DAY	$293	$86	15%	0%	$390	0.000	0.071	155%	18%	0%	0%
DEOK	$293	$89	15%	10%	$635	0.018	0.089	119%	11%	4%	3%
Net CONE 5% Higher than Parent, LDA Cap at 1.7xNet CONE											
PEPCO	$323	$118	5%	8%	$813	0.030	0.136	125%	16%	6%	5%
COMED	$330	$121	0%	33%	$2,932	0.025	0.095	105%	5%	11%	8%
PPL	$308	$104	6%	10%	$884	0.064	0.144	119%	13%	5%	5%
DAY	$293	$84	10%	0%	$390	0.000	0.070	206%	17%	0%	0%
DEOK	$293	$88	10%	3%	$632	0.005	0.074	125%	12%	2%	1%
Net CONE 5% Higher than Parent, LDA Cap at 1.7xNet CONE and Width at Least 25% of CETL											
PEPCO	$323	$113	4%	10%	$823	0.014	0.108	128%	16%	4%	4%
COMED	$330	$120	0%	32%	$2,930	0.025	0.095	105%	5%	11%	8%
PPL	$308	$102	4%	11%	$890	0.038	0.119	121%	13%	4%	3%
DAY	$293	$84	8%	0%	$390	0.000	0.070	195%	21%	0%	0%
DEOK	$293	$89	8%	6%	$633	0.007	0.077	122%	12%	2%	2%

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.
Only included the five worst performing LDAs when Net CONE is always 5% higher than that of the parent.
Results assume that the market entry price is equal to administrative Net CONE.

In addition, we re-iterate four additional recommendations affecting local VRR curves made in our 2014 study. These recommendations are not strictly about the VRR curve shape and thus are not directly within the scope of the review prescribed in PJM's tariff, but could help to support locational reliability, stability, and pricing that is more aligned with reliability value:

1. **Consider defining local reliability objectives in terms of normalized unserved energy.** We recommend that PJM evaluate options for revising the definition of local reliability objective, currently set at a 1-in-25 conditional LOLE standard. Instead, PJM could explore options for an alternative standard based on normalized expected unserved energy, which is the expected outage rate as a percentage of total load. We also recommend exploring this alternative standard based on a multi-area reliability model

that simultaneously estimates the location-specific EUE among different PJM system and sub-regions. The result would be a reliability standard that better accounts for the level of correlation between system-wide and local generation outages, and results in a more uniform level of reliability for LDAs of different sizes and import dependence.

2. **Consider alternatives to the "nested" LDA structure.** We recommend that PJM consider generalizing its approach to modeling locational constraints in RPM beyond import-constrained, nested LDAs with a single import limit. As the number of modeled LDAs increases and the system reserve margin decreases, different types of constraints may emerge that do not correspond to a strictly nested model. A more generalized "meshed" LDA model (with simultaneous clearing during the auction) would explicitly allow for the possibility that some locations may be export-constrained, that some LDAs may have multiple transmission import paths, and some may have the possibility of being either import- or export-constrained, depending on RPM auction outcomes.[84]

3. **Evaluate options for increasing stability of CETL.** We recommend that PJM continue to review its options for increasing the predictability and stability of its CETL estimates. Based on our simulation results, we find that reducing CETL uncertainty could significantly reduce capacity price volatility in LDAs. Physical changes to the transmission system do need to continue to be reflected as changes in CETL, but reducing uncertainty would provide substantial benefits in reducing price volatility. We suggested several options to evaluate for mitigating volatility in CETL in our 2011 RPM Review.

4. **Consider revising the RPM auction clearing mechanics within LDAs based on delivered reliability value.** As another option for enhancing locational capacity price stability and overall efficiency, we recommend that PJM consider revising its auction-clearing mechanics to produce prices that are more proportional to the marginal reliability value of incremental resources in each LDA. Such a mechanism would determine the lowest-cost resources for achieving local reliability objectives by selecting either: (a) a greater quantity of lower-cost imports from outside the LDA, but recognizing the lower reliability of imported resources (due to transmission import capability risk and lost diversity benefits as an LDA becomes more import-dependent); or (b) a smaller quantity of locally-sourced resources with greater reliability value (*i.e.*, without the additional transmission availability risk). This approach would stabilize LDA pricing by allowing for more gradual price separation as an LDA becomes more import-dependent (rather than price-separating only once the administratively-set import constraints bind).[85]

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84 The IMM recently recommended that PJM implement a nodal capacity market. The principle underlying the IMM's recommendation—to align more closely the market with the characteristics of the actual electrical facts of the grid—is the same principle that motivates our recommendation to consider alternatives to the "nested" LDA structure. See Monitoring Analytics (2017).

85 See our 2014 study for a more detailed discussion on clearing mechanics for locational reliability value, Pfeifenberger (2014). ISO-NE recently implemented their Marginal Reliability Impact based demand curves to address this in their market, see ISO-NE (2016).

List of Acronyms

A/S	Ancillary Service
AESO	Alberta Electricity System Operator
ATSI	American Transmission Systems, Inc. (a FirstEnergy subsidiary)
ATSI-C	American Transmission Systems, Inc.-Cleveland
ATWACC	After-Tax Weighted-Average Cost Of Capital
BGE	Baltimore Gas and Electric Company
BLS	Bureau of Labor Statistics
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, aka DAY
DEOK	Duke Energy Ohio/Kentucky
DPL-South	Delmarva Power and Light-South
DR	Demand Response
E&AS	Energy and Ancillary Services
EKPC	East Kentucky Power Cooperative, Inc.
EMAAC	Eastern Mid-Atlantic Area Council
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operation and Maintenance
FPR	Forecast Pool Requirement
FRR	Fixed Resource Requirement
IA	Incremental Auction
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
LMP	Locational Marginal Price
LOLE	Loss of Load Event
LSE	Load-Serving Entities
MAAC	Mid-Atlantic Area Council
MetEd	Metropolitan Edison Company
MISO	Midcontinent Independent System Operator
MOPR	Minimum Offer Price Rule
MW	Megawatts
MWh	Megawatt Hours
NYISO	New York ISO
OATT	Open Access Transmission Tariff
PECO	PECO Energy Company, Exelon Corporation, aka PE
PenElec	Pennsylvania Electric Company
PepCo	Potomac Electric Power Company
PJM	PJM Interconnection, LLC
PPL	Pennsylvania Power and Light Company
PS-North	Public Service Enterprise Group-North
PSEG	Public Service Enterprise Group
PSEG North	Public Service Enterprise Group-North
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SWMAAC	Southwestern Mid-Atlantic Area Council
UCAP	Unforced Capacity
VOM	Variable Operations and Maintenance
VRR	Variable Resource Requirement
WMAAC	Western Mid-Atlantic Area Council

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Appendix A: Magnitude of Monte Carlo Fluctuations

In this appendix we provide additional detail on our approach to estimating and implementing a realistic magnitude of fluctuations into our Monte Carlo simulation modeling, including fluctuations to: (1) supply offer quantity; (2) reliability requirement; (3) administrative net CONE; and (4) CETL. A summary of these fluctuations and the combined supply minus demand fluctuations in each location is included in Section III.E above.

A. Supply Offer Quantity

We estimate gross supply fluctuations based on the range of actual total supply offer quantities in historical BRAs over delivery years 2009/10 to 2020/21, based on offer data provided by PJM. Table 21 summarizes the total supply offered by LDA, as well as several series of historical fluctuations calculated in different ways, based on the distributions of total supply offers, year-to-year changes in supply offers, and differences in supply offers relative to a linear time trend and spline interpolation time trend. We determine reasonable supply fluctuations magnitudes based on the historical fluctuations as an exponential function of LDA size, resulting in the final supply fluctuations values shown in column 9 of Table 21.

Table 21
Fluctuations in Supply Offers

	Total Supply Offered by Delivery Year												Standard Deviation of Historical Fluctuations								Simulated Fluctuation Std. Dev
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total Offers	Annual Change in Offer	Diff. from Trend	Diff. from Spline	Total Offers	Annual Change in Offer	Diff. from Trend	Diff. from Spline	
	(MW)	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)* [1]	*(MW)* [2]	*(MW)* [3]	*(MW)* [4]	*(%)* [5]	*(%)* [6]	*(%)* [7]	*(%)* [8]	*(MW)* [9]
RTO Including Subzones																					
Total Offered (No Adjustments)	133,551	133,093	137,720	145,373	160,898	160,486	178,588	184,380	178,839	179,891	185,540	183,352	21,058	7,250	7,159	5,350	13%	4%	4%	3%	2,988
Adjust for Expansions Only [A]	133,551	133,093	137,720	145,373	147,499	147,743	163,694	165,620	161,237	163,298	167,568	165,371	13,264	5,453	4,527	3,723	9%	4%	3%	2%	-
Adjust for FRR Only [B]	156,484	156,900	161,313	169,129	184,458	190,250	192,994	198,585	191,039	194,181	199,484	196,640	16,761	5,869	6,953	4,129	9%	3%	4%	2%	-
Adjust for Expansions and FRR [C]	156,484	156,900	161,313	169,129	171,060	171,493	177,121	178,814	172,593	176,613	180,568	177,685	8,396	3,964	3,657	2,336	5%	2%	2%	1%	-
Parent LDAs Including Sub-LDAs																					
MAAC	63,426	63,820	65,373	68,296	68,338	70,885	74,261	71,608	72,351	73,546	74,633	72,973	4,027	1,835	1,604	1,074	6%	3%	2%	2%	2,356
EMAAC	31,639	31,075	31,876	32,983	33,007	34,520	37,226	34,140	33,706	33,840	33,228	31,045	1,730	1,632	1,669	1,024	5%	5%	5%	3%	1,338
SWMAAC	10,312	10,928	11,651	12,396	11,768	12,458	12,722	12,386	12,645	12,621	13,300	12,895	860	509	412	311	7%	4%	3%	3%	622
ATSI	n/a	n/a	n/a	n/a	13,335	12,679	11,777	12,791	12,173	11,086	11,848	11,705	722	822	488	488	6%	7%	4%	4%	569
PSEG	6,995	7,244	7,427	7,461	8,064	8,215	8,964	6,796	6,833	6,939	6,634	5,700	849	811	764	471	12%	11%	11%	6%	295
Average LDA Fluctuation													**1,638**	**1,122**	**987**	**674**	**7%**	**6%**	**5%**	**4%**	**1,036**
Smallest LDAs																					
PEPCO	5,064	5,498	5,670	5,382	5,289	5,875	6,235	6,126	6,134	5,991	6,787	6,941	576	339	251	251	10%	6%	4%	4%	336
PS-North	3,429	3,526	3,665	3,745	4,155	4,151	4,912	4,162	4,019	3,645	3,727	3,359	432	406	431	233	11%	10%	11%	6%	170
ATSI-Cleveland	n/a	n/a	n/a	n/a	2,232	2,341	1,657	2,874	2,561	2,590	2,487	2,467	355	587	326	326	15%	24%	14%	14%	126
DPL-South	1,505	1,546	1,460	1,499	1,612	1,600	1,768	1,767	1,686	1,748	1,724	1,688	111	78	65	60	7%	5%	4%	4%	85
BGE	3,538	3,721	4,271	5,310	4,771	4,919	4,792	4,578	4,107	4,225	4,101	3,543	565	485	563	281	13%	11%	13%	7%	184
ComEd	24,585	24,139	24,635	25,647	26,748	25,945	27,412	26,650	26,701	26,276	26,589	27,437	1,102	795	637	522	4%	3%	2%	2%	1,204
Dayton	2,337	2,335	2,439	2,742	2,692	2,599	4,438	4,376	4,130	4,145	4,027	1,669	981	953	884	750	31%	30%	28%	24%	85
PPL	8,335	8,339	8,419	9,149	9,447	10,232	10,863	11,097	11,294	11,158	11,167	10,930	1,217	346	457	324	12%	3%	5%	3%	538
DEOK	n/a	n/a	n/a	n/a	n/a	n/a	3,056	3,234	2,840	2,958	3,080	3,167	142	235	141	125	5%	8%	5%	4%	160
Average LDA Fluctuation													**609**	**469**	**417**	**319**	**12%**	**11%**	**10%**	**7%**	**321**

Sources and Notes:

Supply offer data provided by PJM.

[A] Supply located in ATSI, DEOK, and East Kentucky Power Cooperative, Inc. (EKPC) zones are subtracted from Rest of RTO Supply.

[B] Supply from FRR is added to Rest of RTO Supply.

[C] The adjustments from [A] and [B] are combined. For the FRR, adjustment, the portion of the FRR obligation due to DEOK and EKPC are not included.

[1] Standard deviation of total supply offers by delivery year.

[2] Standard deviation of year to year delta in total supply offer.

[3] Standard deviation of MW difference from a linear time trend of total supply offer.

[4] Standard deviation of MW difference from a spline regression time trend of total supply offer.

[5] Column [1] divided by average total historical supply offer.

[6] Column [2] divided by average total historical supply offer.

[7] Column [3] divided by average total historical supply offer.

[8] Column [4] divided by average total historical supply offer.

[9] Exponential formula of column [8] and simulated supply offer fluctuations.

B. Reliability Requirement

We estimate fluctuations in reliability requirement in LDAs as two components: (1) an RTO-correlated fluctuation that is entirely driven by the variation in historical RTO reliability requirements; and (2) an incremental fluctuation driven by variability in historical reliability requirements above the RTO value for each LDA. We calculate historical fluctuations to the reliability requirement as the differences in historical reliability requirement relative to a spline interpolation time trend. For historical reliability requirement values we used historical BRA input parameters, and for missing values (*i.e.*, for historical years a LDA wasn't modeled) we used the forecasted peak load multiplied by the average Forecast Pool Requirement (FPR) from 2007/08 – 2020/21 BRAs.

We determine a reasonable reliability requirement fluctuation magnitude of 1.7% for the RTO based on the standard deviation of historical fluctuations to the system reliability requirement, shown in Table 22.

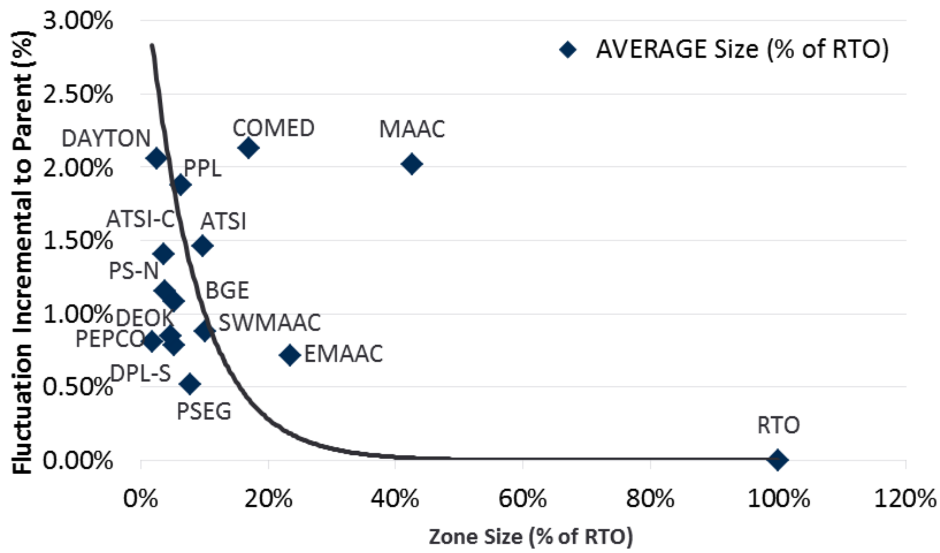
Table 22
Fluctuations in Reliability Requirement

Location	Base Assumptions 2020/21		Simulated Fluctuation Standard Deviation		
	Reliability Requirement *(MW)*	Total Fluctuation *(MW)*	RTO-Correlated *(%)*	Fluctuation on Top of RTO *(%)*	Total Fluctuation *(%)*
	[1]	[2]	[3]	[4]	[5]
RTO	154,355	2,827	1.83%	0.0%	1.83%
MAAC	66,385	1,120	1.83%	0.0%	1.69%
EMAAC	36,921	625	1.83%	0.2%	1.69%
SWMAAC	15,486	314	1.83%	1.1%	2.03%
PSEG	11,797	268	1.83%	1.5%	2.27%
PS-N	6,023	192	1.83%	2.7%	3.18%
DPL-S	2,999	100	1.83%	2.9%	3.33%
PEPCO	7,978	221	1.83%	2.1%	2.78%
ATSI	15,610	319	1.83%	1.1%	2.04%
ATSI-C	5,865	176	1.83%	2.5%	3.01%
COMED	26,224	459	1.83%	0.5%	1.75%
BGE	8,132	231	1.83%	2.3%	2.84%
PPL	9,829	233	1.83%	1.7%	2.37%
DAYTON	4,027	129	1.83%	2.7%	3.19%
DEOK	7,102	199	1.83%	2.0%	2.80%

Source and Note:
Reliability requirement is net of FRR, see PJM (2017c).

We develop reasonable uncorrelated fluctuations on top of the RTO-correlated fluctuations for the LDAs based on the historical fluctuations as an exponential function of LDA size, shown in Figure 23. To calculate the total fluctuation size for each LDA we add the RTO-correlated fluctuation to the uncorrelated fluctuations of the LDA and its parent(s). The final fluctuation sizes are displayed in Table 22.

Figure 23
LDA Reliability Requirement Uncorrelated Fluctuation



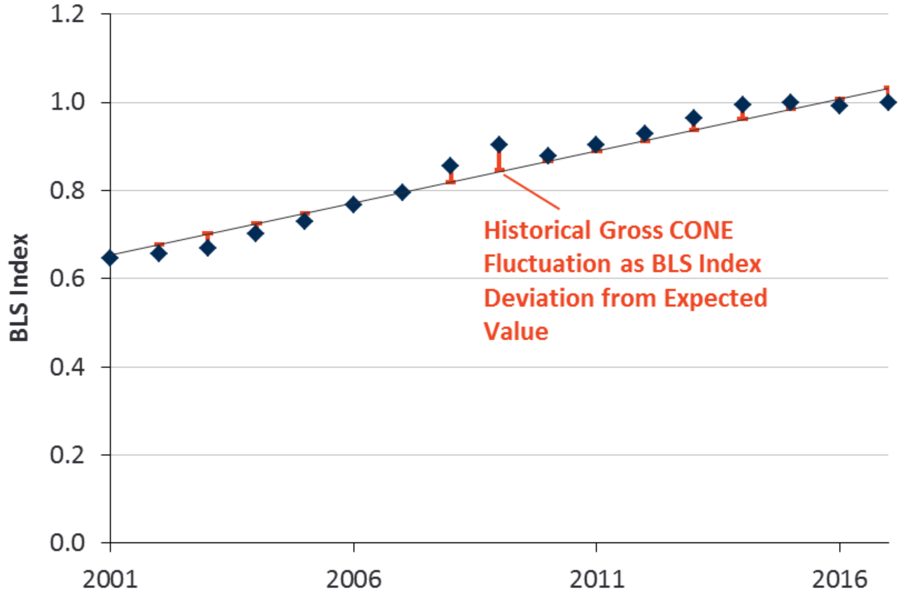
Sources and Notes:

Zone Size calculated based on average reliability requirement from 2007/08–2020/21. Reliability requirement created using a combination of BRA input parameters and forecasted peak load. See PJM Planning Period Parameters for the years 20072017.

C. Administrative Net CONE

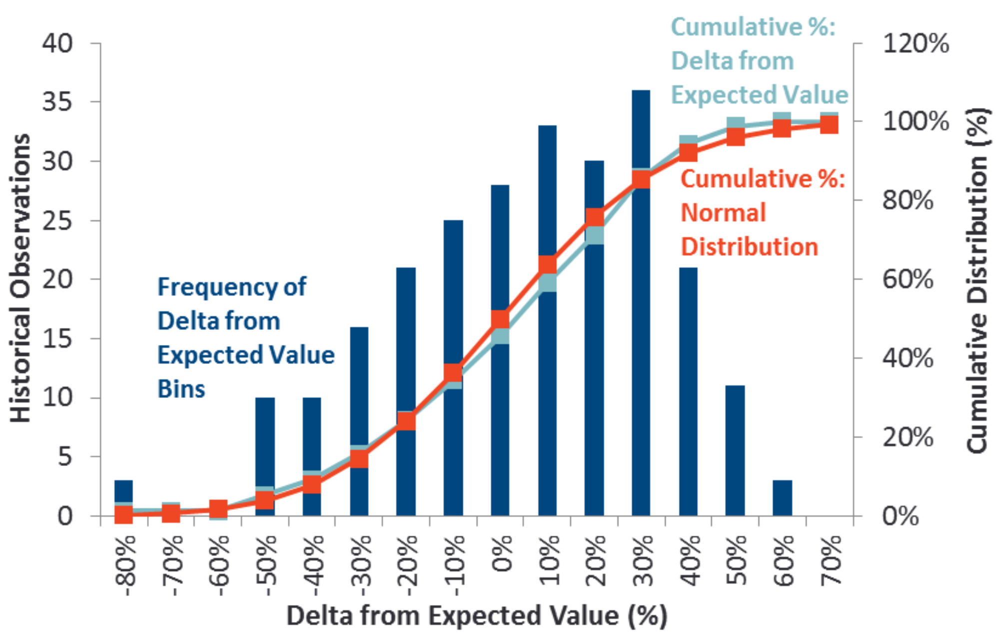
We develop Net CONE fluctuations as the sum of fluctuations to Gross CONE and a 3-year average E&AS fluctuation. We model Gross CONE fluctuations of 3.1% based on deviations away from a long-term trend in the composite BLS index PJM uses to inflate Gross CONE year to year, as illustrated in Figure 24. For the E&AS fluctuations, we find the deviation of administrative E&AS estimates in each year from a fitted trend over 2001–2017. The standard deviation of these one-year historical E&AS estimates around the expected value is 28.4%, as summarized in Figure 25, which compares the one-year E&AS fluctuations relative to a normal distribution.

Figure 24
BLS Index



Sources and Notes:
Based on the composite BLS index PJM uses to inflate Gross CONE year to year, see PJM (2017f).

Figure 25
One-Year E&AS Fluctuations



Sources:
Historical E&AS revenues provided by PJM.

Consistent with the current PJM administrative Net CONE methodology, we estimate E&AS offset based on a rolling three-year average E&AS (or the average of three independent draws from the one-year E&AS distribution shown above). This results in a 16.5% standard deviation in the three-year average E&AS offset, compared to a 28.4% standard deviation in the one-year E&AS offset. The resulting standard deviation in administrative Net CONE combines the fluctuations in both Gross CONE and E&AS as summarized in Table 23, resulting in a 7.1% standard deviation in administrative Net CONE for RTO under our Base Case assumptions.

Table 23
Administrative Net CONE Fluctuations

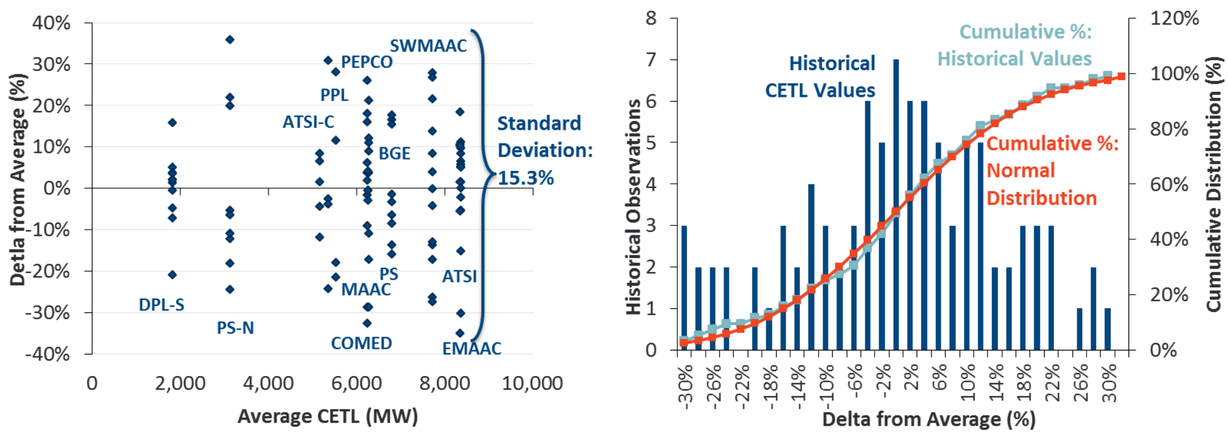
LDA	Base Assumptions from 2020/21				Standard Deviation of Fluctuation Components			
	Expected Gross CONE	Expected E&AS	Expected Net CONE	Net CONE Fluctuations	Gross CONE	One-Year E&AS	Three-Year E&AS	Net CONE
	($/MW-d)	*($/MW-d)*	*($/MW-d)*	*($/MW-d)*	*(%)*	*(%)*	*(%)*	*(%)*
RTO	$394	$101	$293	$21	3.1%	28.4%	16.5%	7.1%
ATSI	$391	$130	$261	$25	3.1%	28.4%	16.5%	9.5%
ATSI-C	$391	$130	$261	$25	3.1%	28.4%	16.5%	9.5%
MAAC	$395	$142	$252	$27	3.1%	28.4%	16.5%	10.5%
EMAAC	$394	$111	$283	$22	3.1%	28.4%	16.5%	7.8%
SWMAAC	$401	$199	$202	$35	3.1%	28.4%	16.5%	17.4%
PSEG	$394	$87	$307	$19	3.1%	28.4%	16.5%	6.2%
DPL-S	$394	$139	$255	$26	3.1%	28.4%	16.5%	10.2%
PS-N	$394	$87	$307	$19	3.1%	28.4%	16.5%	6.2%
PEPCO	$401	$175	$227	$31	3.1%	28.4%	16.5%	13.9%
COMED	$391	$61	$330	$16	3.1%	28.4%	16.5%	4.8%
BGE	$401	$223	$178	$39	3.1%	28.4%	16.5%	21.8%
PPL	$391	$124	$267	$24	3.1%	28.4%	16.5%	9.0%
DAY	$391	$118	$273	$23	3.1%	28.4%	16.5%	8.5%
DEOK	$391	$109	$282	$22	3.1%	28.4%	16.5%	7.7%

Sources and Notes:
Expected Gross CONE, E&AS, and Net CONE consistent with 2020/21 Planning Parameters, see PJM (2017c.)
Historical fluctuations expressed as average of deviations from "trend" in Net CONE, although most LDAs have few data points.

D. Capacity Emergency Transfer Limit

We find that fluctuations are proportional to absolute CETL size but are relatively constant as a percent of CETL, as summarized in Figure 26. We estimate a 15.3% standard deviation on average across all locations in all years. We implement this 15.3% standard deviation using a normal distribution around the 2020/21 CETL value for each location as summarized in Table 24.

Figure 26
Historical CETL as Delta from Average



Sources and Notes:
Historical CETL value from PJM Planning Parameters. See PJM Planning Period Parameters for the years 2007–2017.

Table 24
Historical and Simulation CETL Fluctuations

LDA	Historical CETL Values			Simulation CETL Values		
	Average (MW)	Standard Deviation (MW)	Standard Deviation (%)	2020/21 Value (MW)	Standard Deviation (MW)	Standard Deviation (%)
MAAC	6,257	1,195	19%	4,218	647	15.3%
EMAAC	8,376	966	12%	8,800	1,349	15.3%
SWMAAC	7,730	1,472	19%	9,802	1,503	15.3%
PSEG	6,803	898	13%	8,001	1,226	15.3%
PS-N	3,139	649	21%	4,264	654	15.3%
DPL-S	1,833	167	9%	1,872	287	15.3%
PEPCO	6,290	1,076	17%	7,625	1,169	15.3%
ATSI	8,352	1,596	19%	9,889	1,516	15.3%
ATSI-C	5,170	428	8%	5,605	859	15.3%
COMED	5,368	1,224	23%	4,064	623	15.3%
BGE	6,273	184	3%	6,244	957	15.3%
PPL	5,532	1,321	24%	7,084	1,086	15.3%
DAYTON	3,401	-	-	3,401	521	15.3%
DEOK	5,072	-	-	5,072	778	15.3%

Sources and Notes:
Historical CETL values from Planning Parameters, PJM Planning Period Parameters for the years 2007–2017.
Simulation CETL values are equal to 15.3% of the 2020/21 CETL value.

E. NET SUPPLY

As discussed in Section III.E, the net supply comparison is the most important driver of price and quantity in our model, as well as in historic market results. We calculate net supply fluctuations as the supply plus CETL minus reliability requirement. All supply, CETL, reliability requirement and net supply fluctuations are shown in Table 25. The simulated net supply fluctuations generally fall between the simple standard deviation of historical values and the de-trended values for the RTO and most LDAs, suggesting that they are a reasonable estimate.

Table 25
Net Supply Fluctuations

LDA	Standard Deviation: Supply (MW)	Standard Deviation: CETL (MW)	Standard Deviation: Reliability Requirement (MW)	Standard Deviation: Net Supply (MW)	Standard Deviation as % of 2020/21 RR: Supply (%)	Standard Deviation as % of 2020/21 RR: CETL (%)	Standard Deviation as % of 2020/21 RR: Reliability Requirement (%)	Standard Deviation as % of 2020/21 RR: Net Supply (%)
Historical Absolute Value (2009/10 - 2020/21)								
RTO	21,058	n/a	14,200	8,870	13.6%	n/a	9.2%	5.7%
ATSI	722	1,596	364	1,728	4.6%	10.2%	2.3%	11.1%
ATSI-CLEVELAND	355	428	152	489	6.1%	7.3%	2.6%	8.3%
MAAC	4,027	1,195	2,089	4,963	6.1%	1.8%	3.1%	7.5%
EMAAC	1,730	616	1,160	2,080	4.7%	1.7%	3.1%	5.6%
SWMAAC	860	1,258	691	2,535	5.6%	8.1%	4.5%	16.4%
PSEG	849	898	530	894	7.2%	7.6%	4.5%	7.6%
DPL-SOUTH	111	167	75	226	3.7%	5.6%	2.5%	7.5%
PS-NORTH	432	649	136	530	7.2%	10.8%	2.3%	8.8%
PEPCO	576	1,076	473	1,984	7.2%	13.5%	5.9%	24.9%
BGE	565	184	344	253	6.9%	2.3%	4.2%	3.1%
COMED	1,102	1,224	1,069	690	4.2%	4.7%	4.1%	2.6%
DAY	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
PPL	1,217	1,321	308	1,458	12.4%	13.4%	3.1%	14.8%
DEOK	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Historical Deviation from Trend (2009/10 - 2020/21)								
RTO	5,350	n/a	6,101	3,392	3.5%	n/a	4.0%	2.2%
ATSI	488	668	127	925	3.1%	4.3%	0.8%	5.9%
ATSI-CLEVELAND	326	377	65	447	5.6%	6.4%	1.1%	7.6%
MAAC	1,074	1204	649	2,126	1.6%	1.8%	1.0%	3.2%
EMAAC	1,024	600	370	1,734	2.8%	1.6%	1.0%	4.7%
SWMAAC	311	469	172	840	2.0%	3.0%	1.1%	5.4%
PSEG	471	416	105	664	4.0%	3.5%	0.9%	5.6%
DPL-SOUTH	60	160	26	220	2.0%	5.3%	0.9%	7.3%
PS-NORTH	233	318	69	364	3.9%	5.3%	1.2%	6.0%
PEPCO	251	672	146	846	3.1%	8.4%	1.8%	10.6%
BGE	281	183	84	249	3.5%	2.2%	1.0%	3.1%
COMED	522	409	321	639	2.0%	1.6%	1.2%	2.4%
DAY	n/a	75	n/a	n/a	n/a	1.9%	n/a	n/a
PPL	324	345	198	166	3.3%	3.5%	2.0%	1.7%
DEOK	n/a	473	n/a	n/a	n/a	7.2%	n/a	n/a
Simulation Analysis								
RTO	2,988	n/a	2,827	4,048	1.9%	n/a	1.8%	2.6%
ATSI	569	1,521	319	1,659	3.6%	9.7%	2.0%	10.6%
ATSI-CLEVELAND	126	841	176	875	2.1%	14.3%	3.0%	14.9%
MAAC	2,356	651	1,120	2,681	3.5%	1.0%	1.7%	4.0%
EMAAC	1,338	1,321	625	1,957	3.6%	3.6%	1.7%	5.3%
SWMAAC	622	1,444	314	1,608	4.0%	9.3%	2.0%	10.4%
PSEG	295	1,236	268	1,316	2.5%	10.5%	2.3%	11.2%
DPL-SOUTH	85	283	100	311	2.8%	9.4%	3.3%	10.4%
PS-NORTH	170	659	192	703	2.8%	10.9%	3.2%	11.7%
PEPCO	336	1,177	221	1,249	4.2%	14.8%	2.8%	15.6%
BGE	184	906	231	960	2.3%	11.1%	2.8%	11.8%
COMED	1,204	608	459	1,420	4.6%	2.3%	1.8%	5.4%
DAY	85	500	129	528	2.1%	12.4%	3.2%	13.1%
PPL	538	1,079	233	1,237	5.5%	11.0%	2.4%	12.6%
DEOK	160	753	199	799	2.4%	11.5%	3.0%	12.2%

Sources and Notes:

All values calculated over 2009/10 through 2020/21 delivery years, where data were available.
Standard Deviation percentages are based on each LDA's 2020/21 reliability requirement.

Appendix B: Supply Curves with Capacity Performance

Under Capacity Performance, resources that do not fulfill their capacity obligation during emergency events are penalized, while resources that perform over their obligation are awarded bonus payments.[86] Resources that do not have a capacity obligation are eligible for bonuses on their full output during emergency events, while resources with obligations are only eligible for bonuses on their output in excess of their obligation. Figure 27 summarizes Capacity Performance penalties and bonuses to resources with and without an obligation.

Figure 27
Capacity Performance Penalties and Bonuses

Annual Penalty Charges for CP Resource:	**PPR × (B - A) × H**
Annual Bonus Payments for CP Resources:	**CPBR × (A - B) × H**
Annual Bonus Payments for Resources Without an Obligation:	**CPBR × A × H**

PPR = Performance Penalty Rate ($/MWh)
- Rate charged to under-performing CP resources during performance hours.
- Calculated by PJM for each delivery year by dividing Net CONE by 30 hours.

CPBR = Capacity Performance Bonus Rate ($/MWh)
- Rate paid to over-performing CP resources and resources without a capacity obligation during performance hours.
- CPBR is set such that total bonus payments = total penalties.
- CPBR is less than PPR due to the effect of exemptions, approved outages, and stop-loss provisions.

B = Balancing Ratio (%)
- Average performance of the PJM fleet.
- Performance of CP resources are evaluated relative to this value.

A = Availability (%)
- Actual output of energy + reserves during emergency hours.
- Expressed as a % of UCAP Commitment.

H = Performance Hours
- Number of hours in the year with a performance event.

Sources:
See PJM (2017h), OATT Attachment DD.10.

As discussed in Section III.C, the 2020/21 BRA was the first auction where only Capacity Performance resources were procured.[87] It is important in the context of this review because of how we model supply and the effect of Capacity Performance on the supply curve shape. As we saw in Figure 13, the implementation of Capacity Performance has reduced the number of zero-priced offers and flattened the lower part of the supply curve during the Capacity Performance BRAs compared to the pre-Capacity Performance BRAs.

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86 Bonus payments are funded by the penalty payments charged to non-performing resources.

87 2018/19 and 2019/20 were transition years where Capacity Performance and base resources were both procured.

Under Capacity Performance, resources are expected to offer differently into the BRA to account for reduced bonus payments if they acquire a capacity obligation. Before Capacity Performance was implemented, there was no opportunity cost in offering into the BRA and clearing, but that changed under Capacity Performance. Existing resources that previously acted as a "price taker" in the non-Capacity Performance BRAs because of low net-going forward costs will now increase their supply offer to ensure they make at least what their expected bonus payments would have been if they had no capacity obligation. Figure 28 shows what the new supply offer will be under Capacity Performance.

Figure 28
Adjusted Supply Offer under Capacity Performance

Bonus Opportunity Cost Offer	Investment Decision Offer
PPR × H × B	**Net Going Forward Cost - PPR × H × (A - B)**
Reflects the minimum capacity price at which capacity obligation is more profitable than earning bonus payments as an energy-only resource	Reflects minimum capacity price above which a resource will take on a capacity obligation (rather than mothball, non-entry, or retirement)

Sources and Notes:
These are slightly simplified formulas that apply only if CPBR = PPR (*i.e.* no exceptions to penalty assessment or stop-loss).
We only model changes to the supply curves using the updated "Bonus Opportunity Cost Offer."
Energy-only resource can receive bonus payments on their full output up to B (even if A is larger than B).
See PJM (2017h), OATT Attachment DD.

As illustrated in Figure 13, the low-priced portion of the supply curve has increased on average under Capacity Performance. Figure 13 shows that there is a range of expected H due to the varying degree of offer price increases in the low-priced portion of the supply curves before and after Capacity Performance was implemented.[88] We model the range of market participants' expectation of H based on offer data provided by PJM. In the following two sections we discuss how we estimate the expected performance hours and then implement the updated offers in our supply curves under Capacity Performance.

A. Expected Performance Hours

As discussed in Section III.C, we model the effect of expected H on both *average* offers and the range of participants' expectation of H under Capacity Performance. To estimate the *average* expected H, we analyze BRA offer data provided by PJM, expected performance hours by reserve margins using PJM LOLE data, and historical performance hours that occurred over the past decade. We consider two types of scarcity that lead to performance hours: installed capacity scarcity and operational scarcity. Installed capacity scarcity is a result of installed capacity falling below a threshold supply buffer above load. Operational scarcity is a result of plants not

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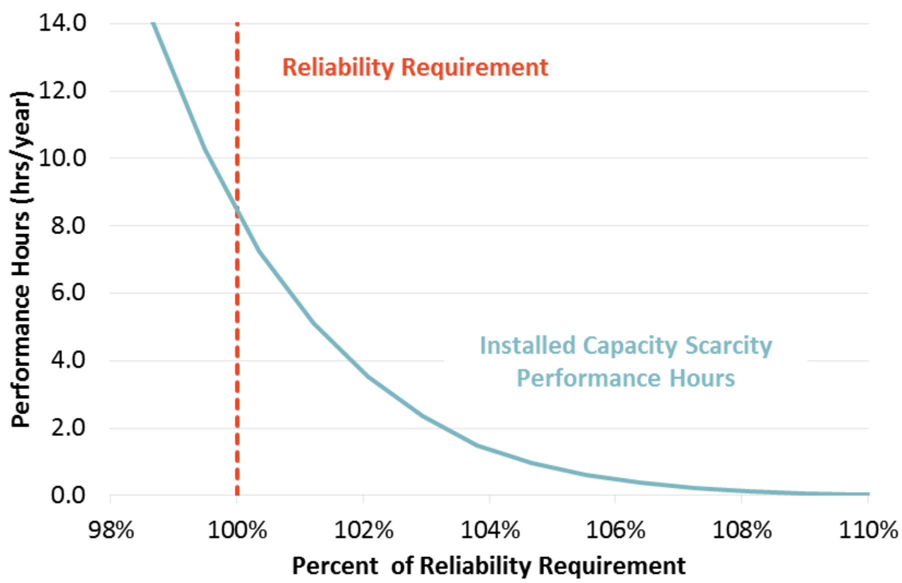
88 If all participants had the same expected H, the 2020/21 BRA supply curve would have a horizontal segment at \$230/MW-day (PPR = \$293/MW-day ÷ 30, H = 30, B = 78.5%).

operating due to fuel supply or other operability constraints. We use the offer data from the 2018/19 – 2020/21 Capacity Performance BRAs to estimate the range of participants' expected H across supply offers.

To estimate the installed capacity scarcity H, we use PJM's reliability modeling data detailing the expected number of installed capacity scarcity performance hours across a range of reserve margins. Figure 29 shows the expected installed capacity scarcity H across percentages of the reliability requirement. If PJM had just enough capacity to meet 100% of the reliability requirement, there would be an average of about 8 installed capacity performance hours. Historically, PJM has had a high reserve margin above the reliability requirement, so we expect a lower average H for our simulations. To model the average installed capacity scarcity H in each simulated draw, we calculate the reserve margin based on the total supply offered relative to the reliability requirement (after accounting for supply and demand fluctuations in each draw) and determine the corresponding H value from the curve shown in Figure 29.

Figure 29
Installed Capacity Scarcity Performance Hours with Respect to Reliability Requirement



Source:
Results from PJM Reliability Model provided by PJM staff.

Our operating scarcity H is informed by historical PJM performance event data over the past decade. Figure 30 shows the range of performance hours affecting the PJM footprint from 2005 to 2017 (blue line) and also shows the reserve margin over this period (grey line).[89] Given the relatively high reserve margins, installed capacity scarcity was likely not the cause of these events. We capture the effect of expected operating scarcity performance hours in market

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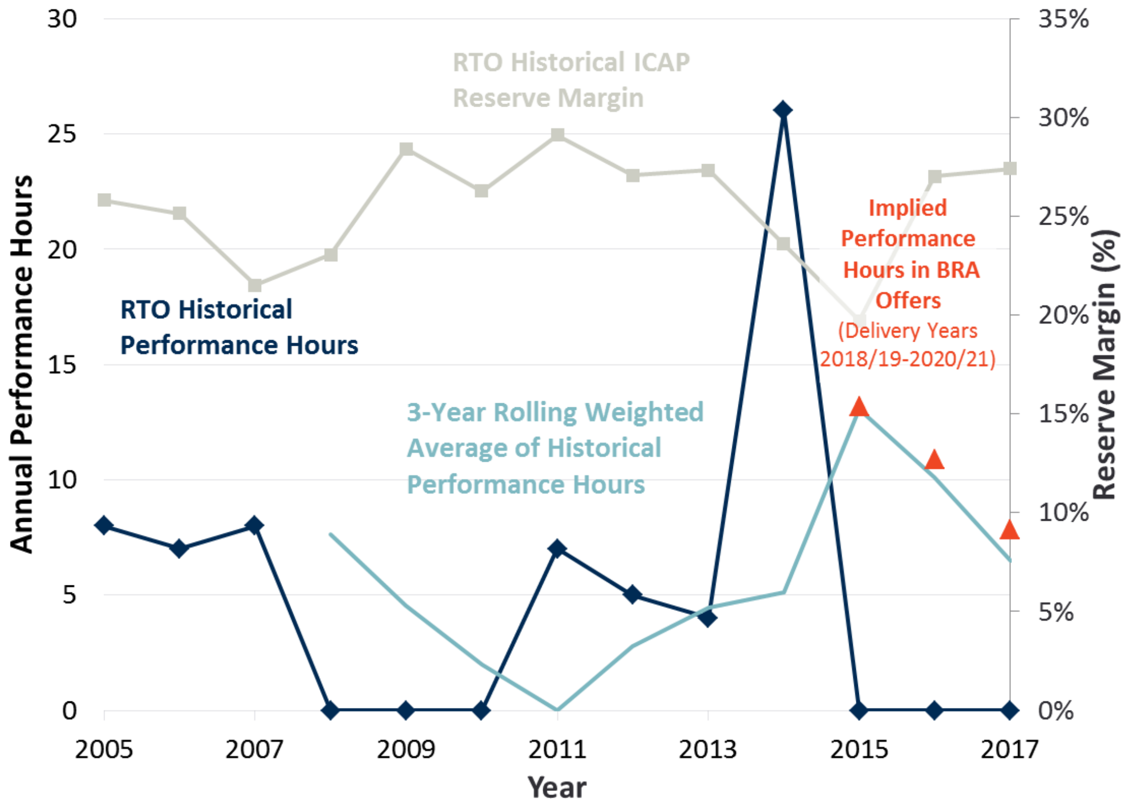
[89] Prior to the introduction of Capacity Performance, PJM did not label tight supply conditions as "performance hours".

participant offers, assuming that the market has a somewhat short memory. For the purposes of our simulation modeling, in each draw we assume that the average market participant reflects operating scarcity performance hours consistent with the range of historical 3-year weighted average performance hours in Figure 29 (teal line).[90] The average operating scarcity H is seven across the simulated draws.

Figure 30
PJM Historical Performance Hours, 2005–2017



Source:
PJM historical performance hour data provided by PJM.
We used publically available data posted on the PJM website for modeling purposes. The small differences between the public data and the data provided by PJM have no effect on our results. See PJM (2015e).
"Implied Performance Hours in BRA Offers" calculated using offer data provided by PJM.
Reserve margin taken from summer reliability reports, see PJM Summer Reliability Assessment for the years 2005-2017.

To check our modeled average H (sum of installed capacity scarcity H and operational scarcity H), we compare it against the average implied expected H using BRA offer data. To calculate the implied expected H of market participants, we focus on zero-priced offers and track how their prices increased between non-Capacity Performance BRAs and Capacity Performance BRAs. This provides three years of data on implied expected H (2018/19–2020/21 BRAs). We calculate

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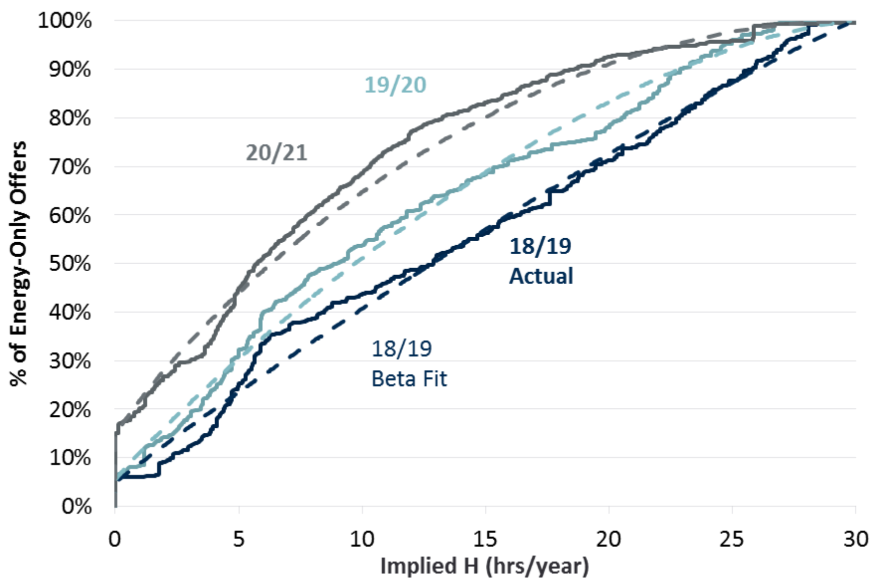
90 There were 10 values to sample from the three-year weighted-average performance-hours data, indicated by the teal line. For each simulated draw, we randomly drew from the 10 values to get an average operational scarcity performance hour value.

the average of each participant's implied H and find a final average H of ten hours, similar to what we model using the approach described above.

After estimating the average H across the market, we use the same offer data from the 2018/19–2020/21 Capacity Performance BRAs to represent diversity in expectations of H across supply offers. To do this we use the offer data provided by PJM and calculate the implied H for each resource, described above. This gave us distributions of implied H by resource offers in the three Capacity Performance BRAs, which resembled a beta distribution for implied H values above zero, as shown in Figure 31. Consequently we used a mixture distribution consisting of zero performance hour offers and beta distributed offers for performance hours between 0 and 30, to represent the diversity in market participants' expectations of H across resource offers in future auctions.

Figure 31
Implied H Cumulative Distributions under Capacity Performance BRAs



Source:
Raw resource offer data provided by PJM staff.

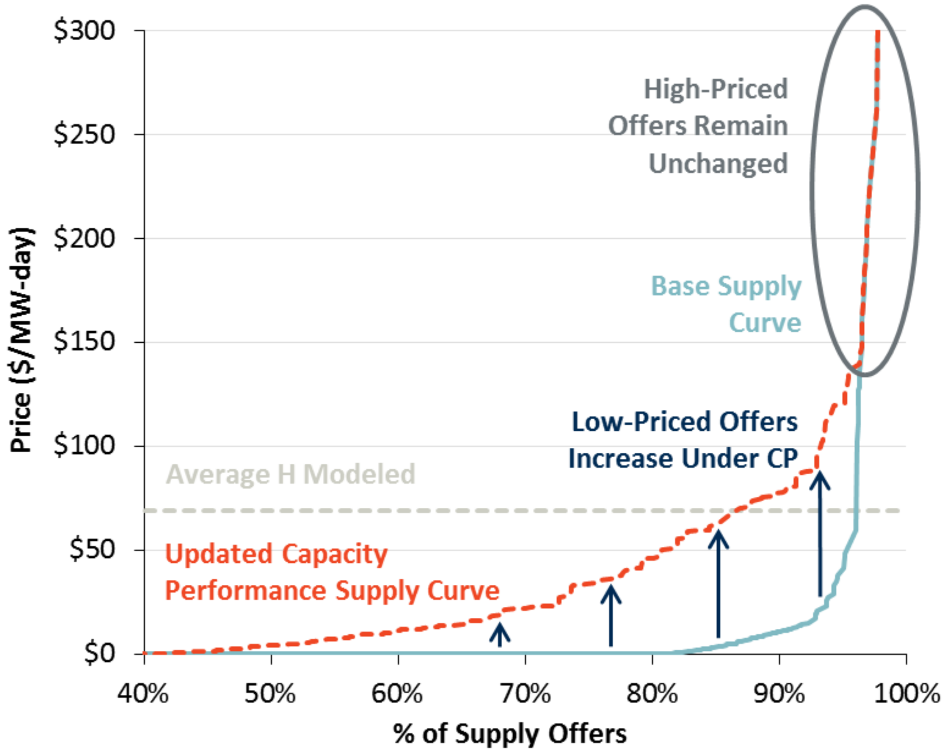
B. Supply Curves Under Capacity Performance

To model supply curves with adjustments under Capacity Performance, we focused on modeling the impact of H. We assumed a penalty rate of Net CONE ÷ 30 and balancing ratio of 78.5%. Expected H across supply offers is driven by both the *average* H in the market and the *diversity of expectations* in H across participants to affect resource offers. For each draw we used an average H, which is calculated as the sum of our installed capacity H estimate and operational scarcity H estimate described in the previous section. For each supply offer, we sampled from the beta mixture distribution based on the average H for that draw, and set that value as the implied H for the supply offer. After calculating an implied H value for each supply offer, we then updated the base supply curve (which is randomly drawn from the non-Capacity

Performance 2009/10–2017/18 BRA supply curves, as discussed in Section III.C with new supply offers depending on the calculated implied H. For each supply offer in the base curve, the new supply offer for the Capacity Performance curve would be the maximum of the base curve offer and new Capacity Performance offer dependent on the implied H value for that participant, described as "Bonus Opportunity Cost Offer" in Figure 28.

By doing this we focused on modeling the effect of Capacity Performance on resource offers from participants who would be online and would receive bonus payments on their full output, *i.e.* resources without capacity obligations as described in Figure 27 and Figure 28. We do this because Capacity Performance has a minimal impact on the high priced offers, those indicated by the higher part of the supply curve. Usually the higher priced offers are resources needing to recover costs from recent infrastructure upgrades or new builds. Unlike the resources that have low going forward costs, who do not need the capacity payments to remain online and generate in the E&AS markets, resources offering in at a high price must recover their going forward costs (less their E&AS revenues) in the capacity market. These resources are less affected by the introduction of Capacity Performance, since the penalties and bonuses only apply to the difference between their output and the average performance of the fleet. Investment decision offers only include this increment in their offers, as detailed in Figure 28. Some suppliers making investment decision offers would expect to receive bonus payments for outperforming their commitment (*e.g.*, new resources) and some would expect to be charged penalties for underperforming their commitment (*e.g.*, old resources seeking a capacity payment to avoid retirement). Overall, there is likely not much impact on the upper portion of the supply curve on average. Figure 32 illustrates how the modeled supply curve changes under Capacity Performance, in which the low-priced portion of the supply curve flattens and increases in price while the high-priced portion of the supply curve remains the same.

Figure 32
Illustrative Example of Supply Curve under Capacity Performance



Source and notes:

Sample base curve shaped using raw resource offer data provided by PJM staff.
PPR = Net CONE ($292.50/MW-day) ÷ 30, balancing ratio = 78.5%, and average H = 9.
Data is based off of one simulated draw of our Monet Carlo simulation.

BOSTON
NEW YORK
SAN FRANCISCO
WASHINGTON
TORONTO
LONDON
MADRID
ROME
SYDNEY

THE Brattle GROUP

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. **)** **Docket No. ER19-___-000**

VERIFICATION

Samuel A. Newell, being first duly sworn, deposes and states that he is the Samuel A. Newell referred to in the foregoing document entitled "Affidavit of Samuel A. Newell and David Luke Oates on Behalf of PJM Interconnection, L.L.C. Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

Subscribed and sworn to before me, the undersigned notary public, this 12th day of October 2018.

Notary Public

My Commission expires: Sep. 4, 2020

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. **)** **Docket No. ER19-___-000**

VERIFICATION

David Luke Oates, being first duly sworn, deposes and states that he is the David Luke Oates referred to in the foregoing document entitled "Affidavit of Samuel A. Newell and David Luke Oates on Behalf of PJM Interconnection, L.L.C. Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," that he has read the same and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

David Luke Oates

Subscribed and sworn to before me, the undersigned notary public, this 11 day of October 2018.

Erica L Deary

Notary Public

My Commission expires: February 15, 2024

ERICA L. DEARY NOTARY PUBLIC COMMONWEALTH OF MASSACHUSETTS My Commission Expires Feb. 15, 2024