Fourth Review of PJM's Variable Resource Requirement Curve

PREPARED FOR

PJM

PREPARED BY

Samuel A. Newell

David Luke Oates

Johannes P. Pfeifenberger

Kathleen Spees

J. Michael Hagerty

John Imon Pedtke

Matthew Witkin

Emily Shorin

April 19, 2018

THE Brattle GROUP

Acknowledgements: 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. Opinions expressed in this report, as well as any errors or omissions, are the authors' alone.

Table of Contents

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:

---

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.

---

[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.

---

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

[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.

---

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.

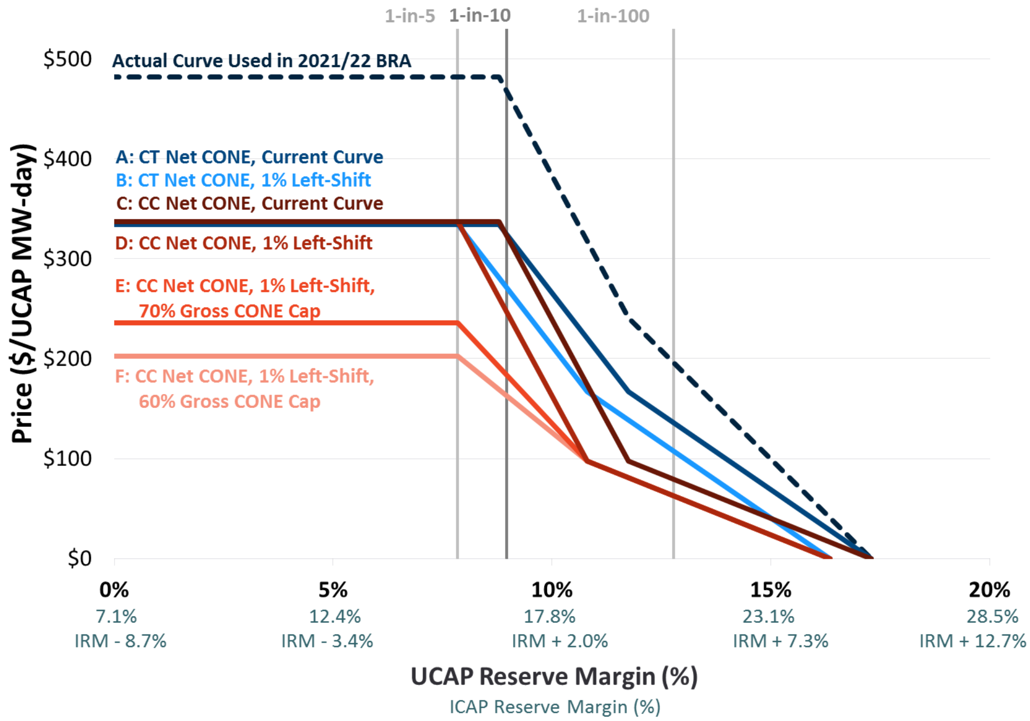
We evaluate the performance of several candidate VRR curves accounting for the reduction in the market entry price, as illustrated in Figure ES-1 alongside PJM's current VRR curve from the 2021/22 auction (**dark blue** dashed line). Table ES-2 reports the performance results of the candidate curves. In evaluating these candidate VRR curves, we assumed that CCs continue to enter the market consistent with our estimate of CC Net CONE.

---

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.

[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 CC 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,

---

[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.

---

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).

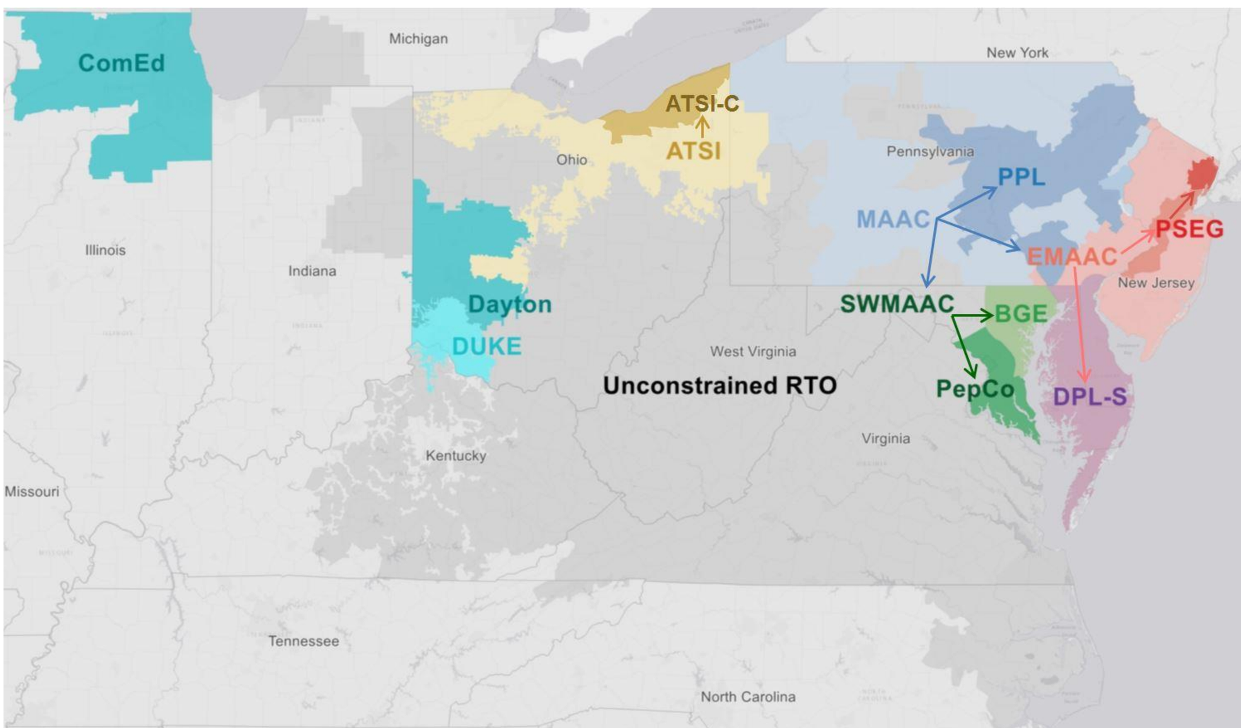
19 See PJM Planning Period Parameters for the years 2007–2017, Pfeifenberger (2008, 2011, 2014). For PJM State of the Market and periodic reports on RPM, see Monitoring Analytics (2014, 2017).

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]

---

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

---

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.

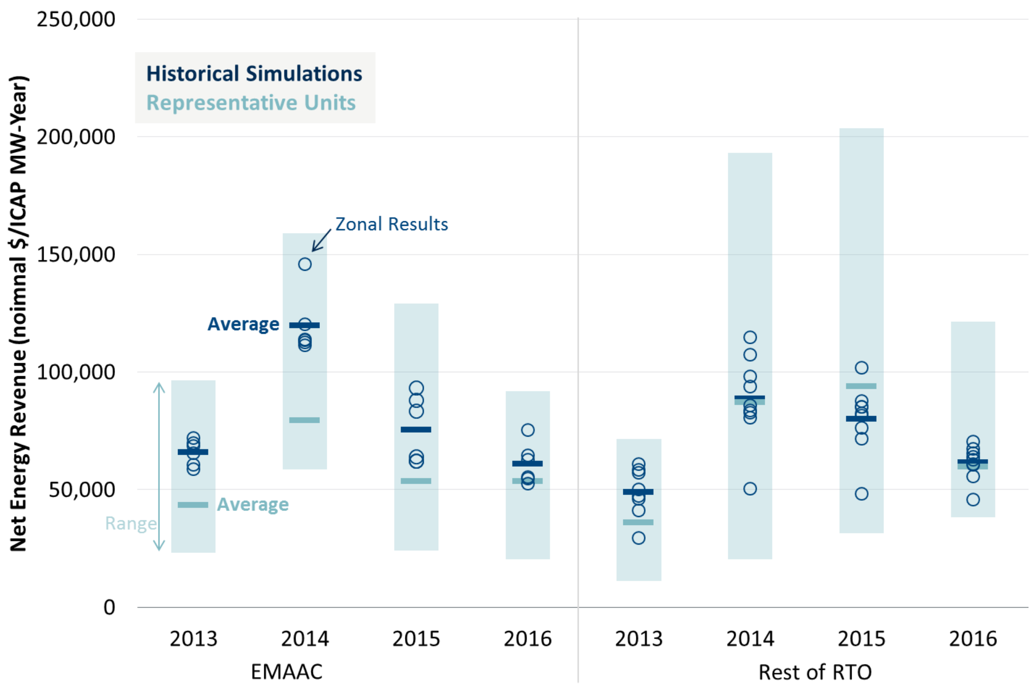
1. PJM's Peak-Hour Dispatch Against Historical Prices

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

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

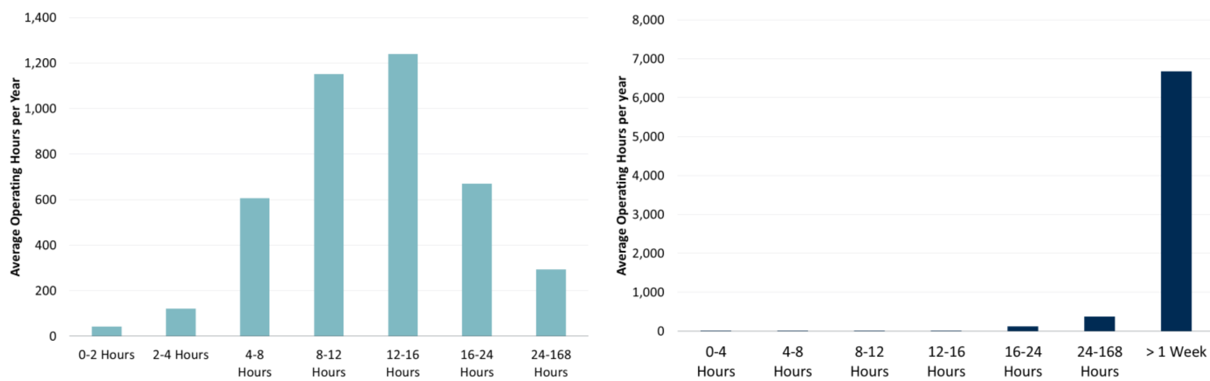
Sources and Notes:
The recommendation for PSEG is a 50%-50% blend of Transco-Z6 (NY) and Transco-Z6 (non-NY) prices.
EV data downloaded from ABB Inc.'s Energy Velocity Suite and Platts data downloaded from S&P Global Market Intelligence between August and December 2017.

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

---

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.

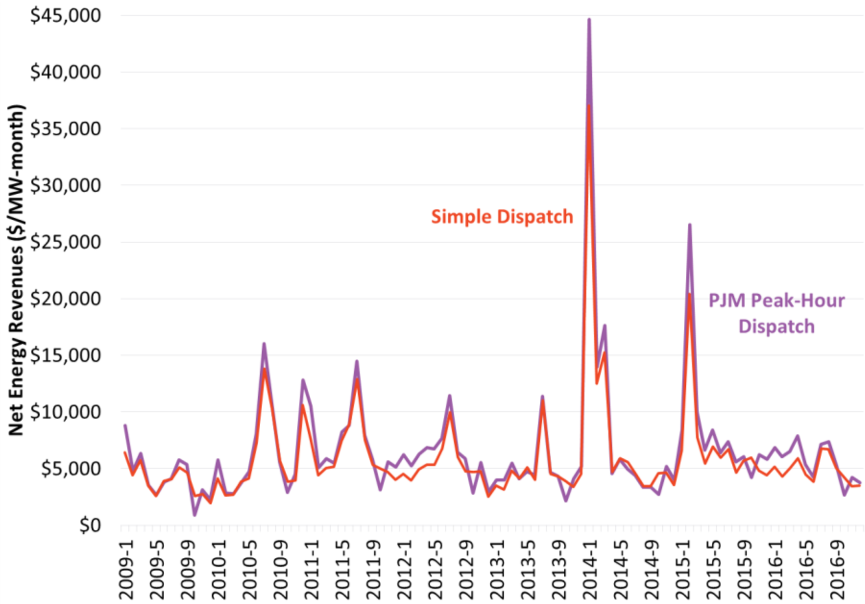
---

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.

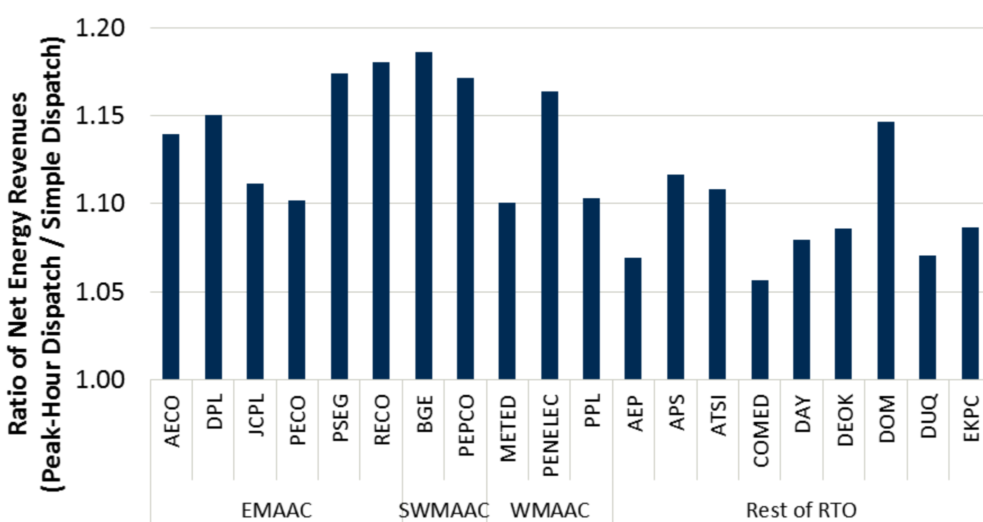
Figure 4
Comparison of Simple Dispatch and Historical Simulation Results in APS



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.

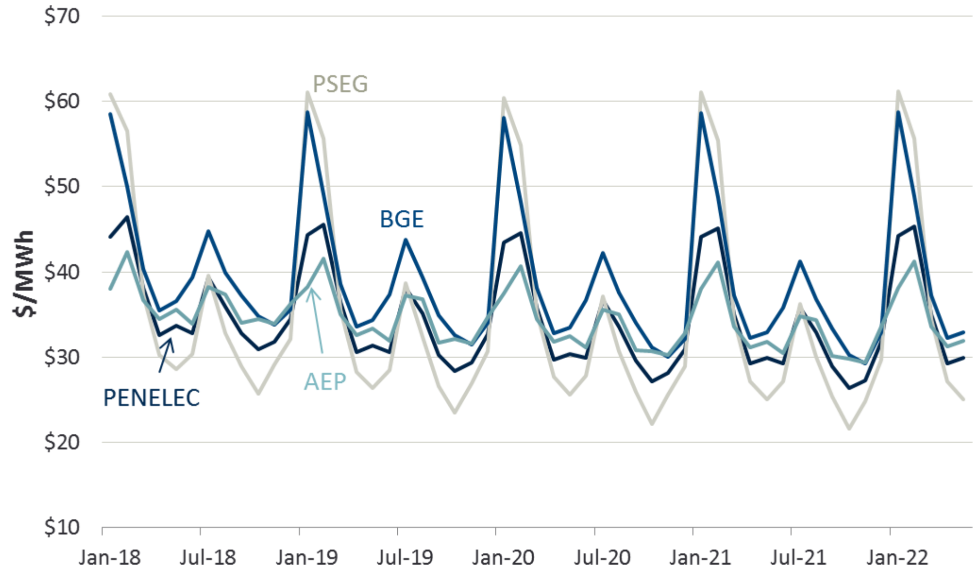
---

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

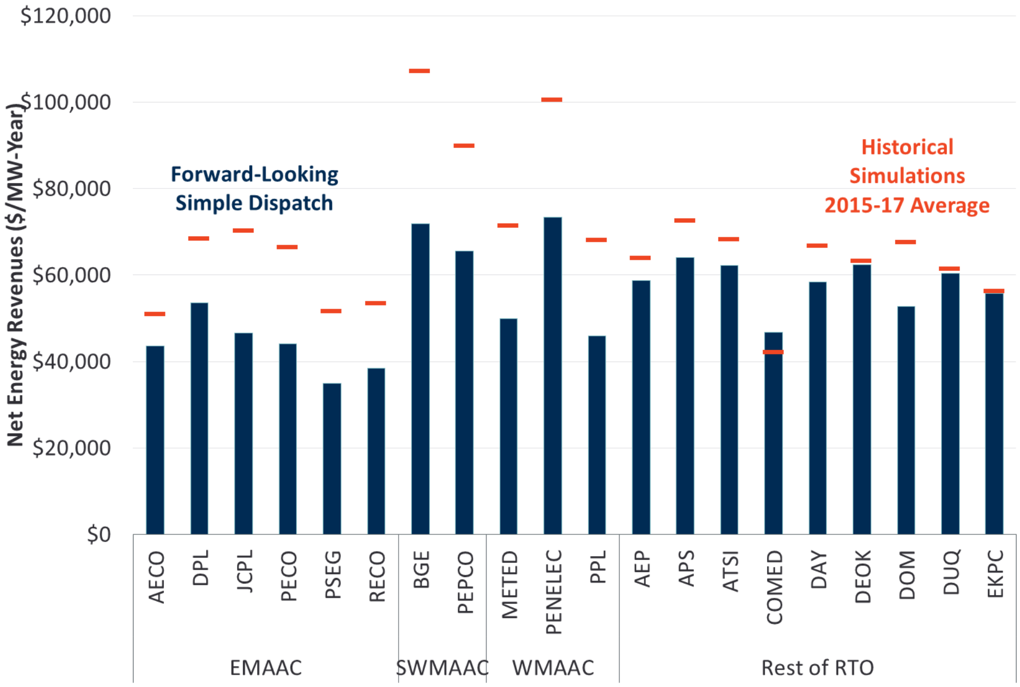


To estimate 2021/22 net energy revenues for a CC in each transmission zone, we dispatched the reference CC using the projected 2021/22 zonal on-peak prices described above and operating costs based on the current assumptions in PJM's historical simulations for operating characteristics (see Table 2 above) 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.

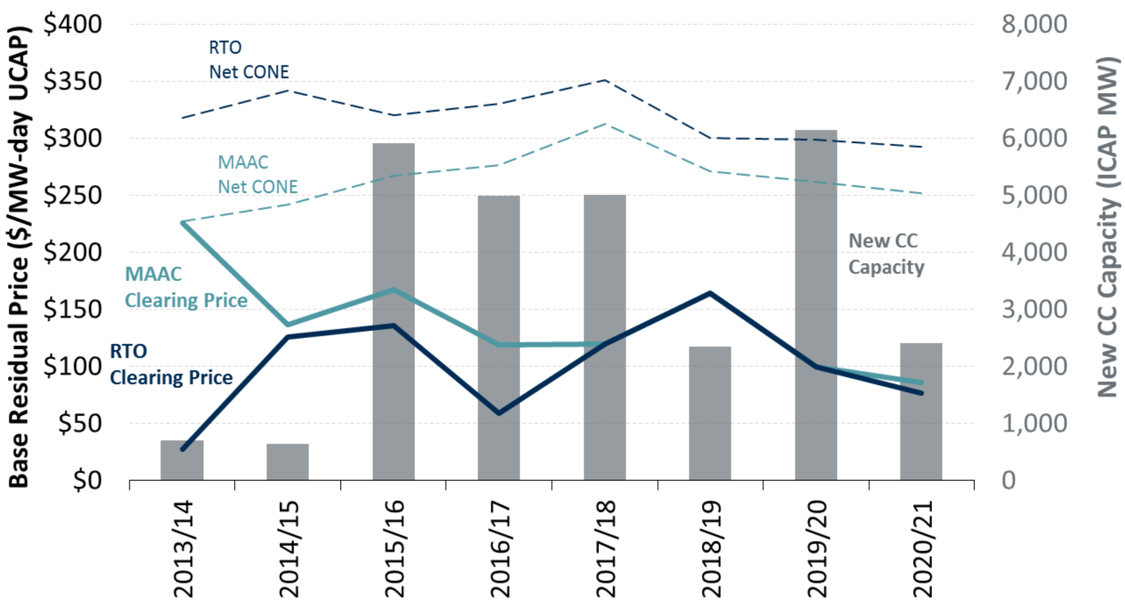
Second, the median should be relatively robust under conditions that deviate from equilibrium. Under conditions where some LDAs have abnormally high E&AS values in the short-run, the median value will not be affected. This will keep Net CONE high enough to support investment in the rest of the footprint. 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

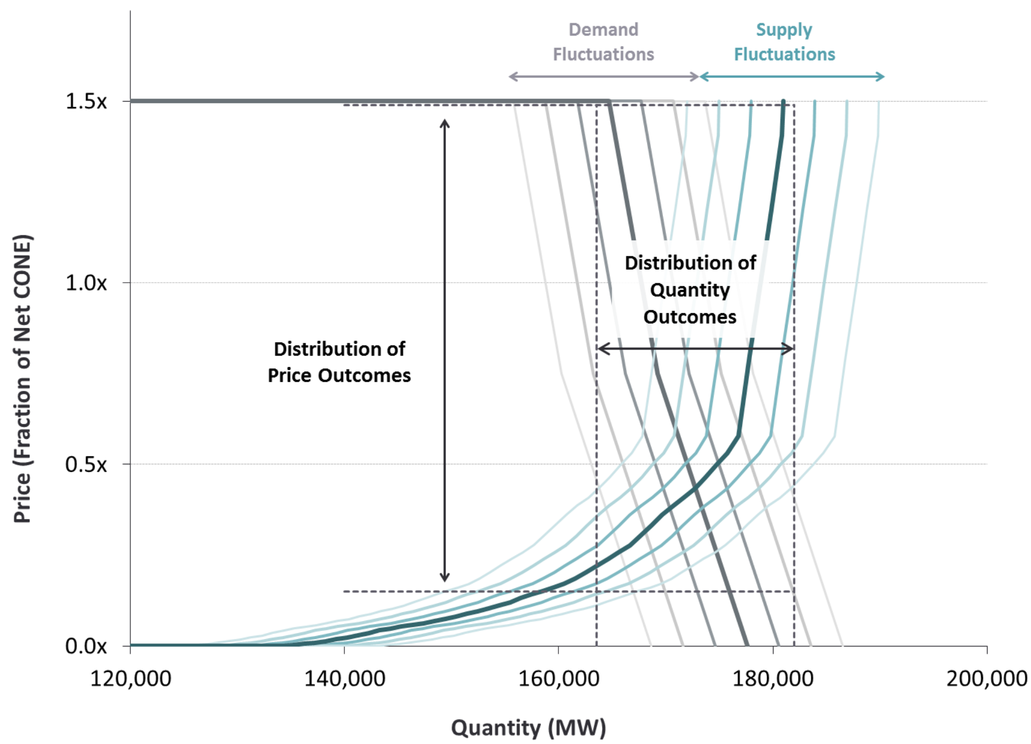
---

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

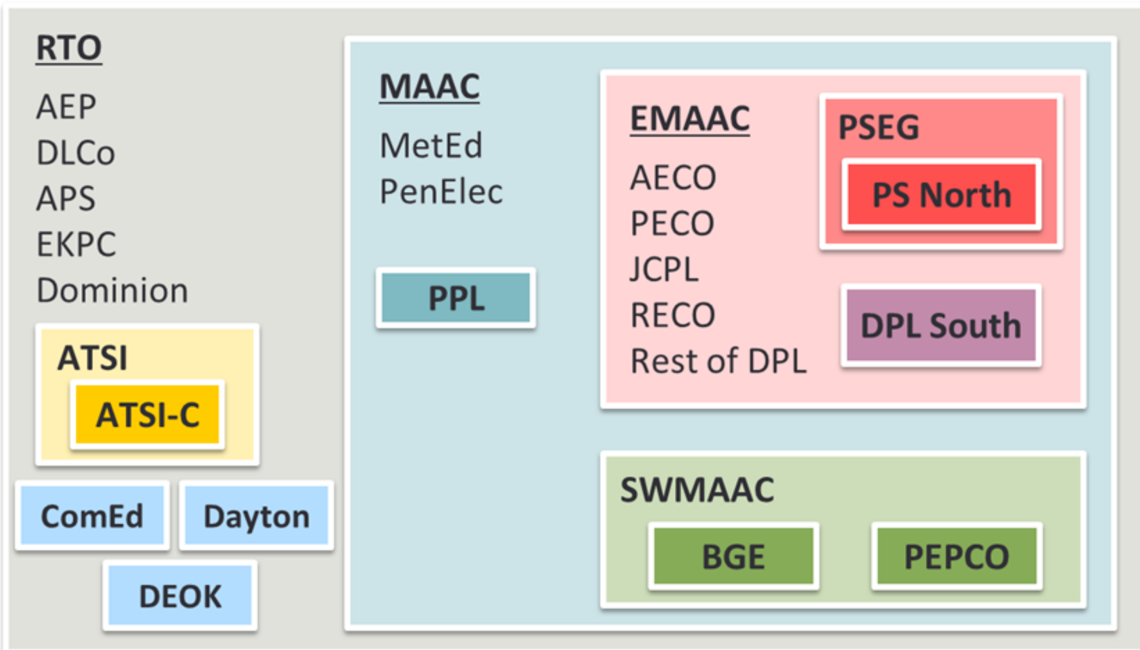
We include administrative demand curves at both system and local levels in a locational clearing algorithm that minimizes capacity procurement costs subject to transmission constraints. We

---

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.

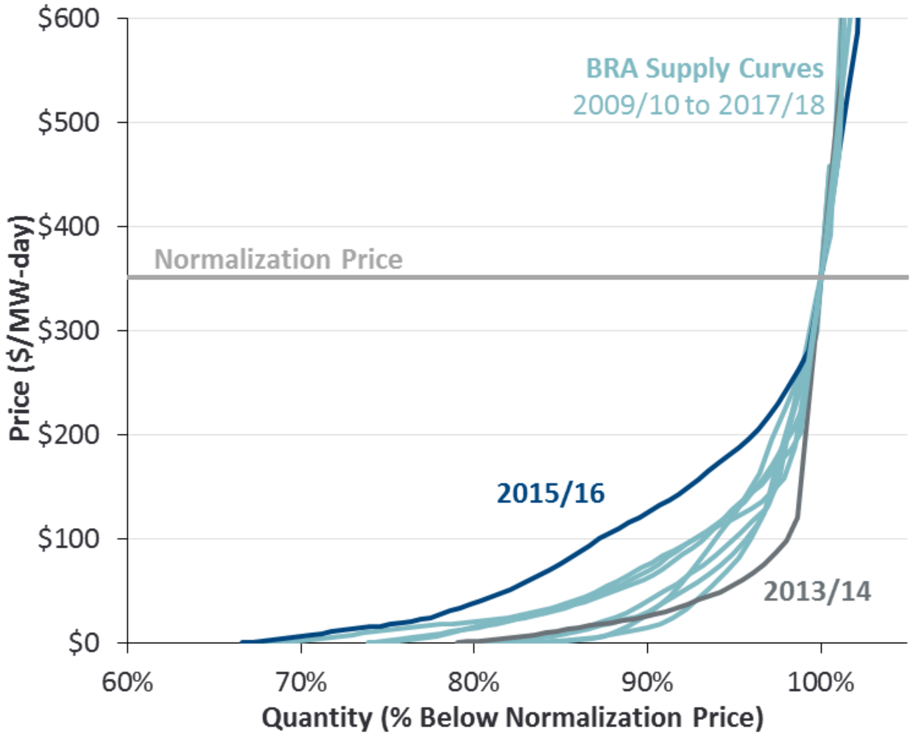
We use historical PJM offer prices and quantities to create nine realistic supply curve shapes, consistent with the supply curve shapes from the PJM BRAs conducted over 2009/10 to 2017/18.[46] To develop comparable supply curve shapes consistent with the 2020/21 delivery year, we escalate all offer prices 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.

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.

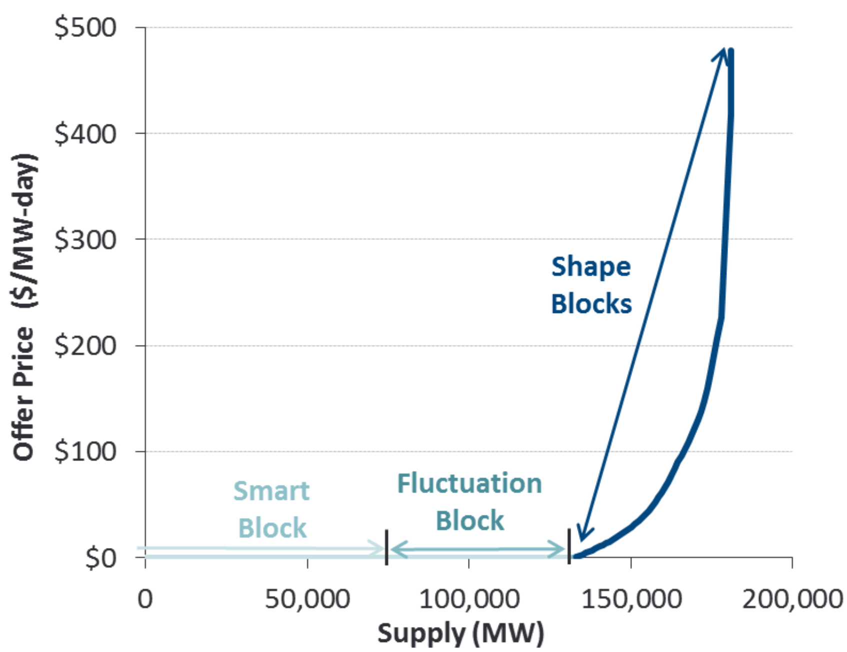
To simulate rational economic entry, we increase or decrease the quantity of zero-priced supply so that the average clearing price over all draws is equal to Net CONE.[49] The result is that average-clearing prices will always converge to Net CONE under all possible demand curves, although differently-shaped 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

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.

---

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

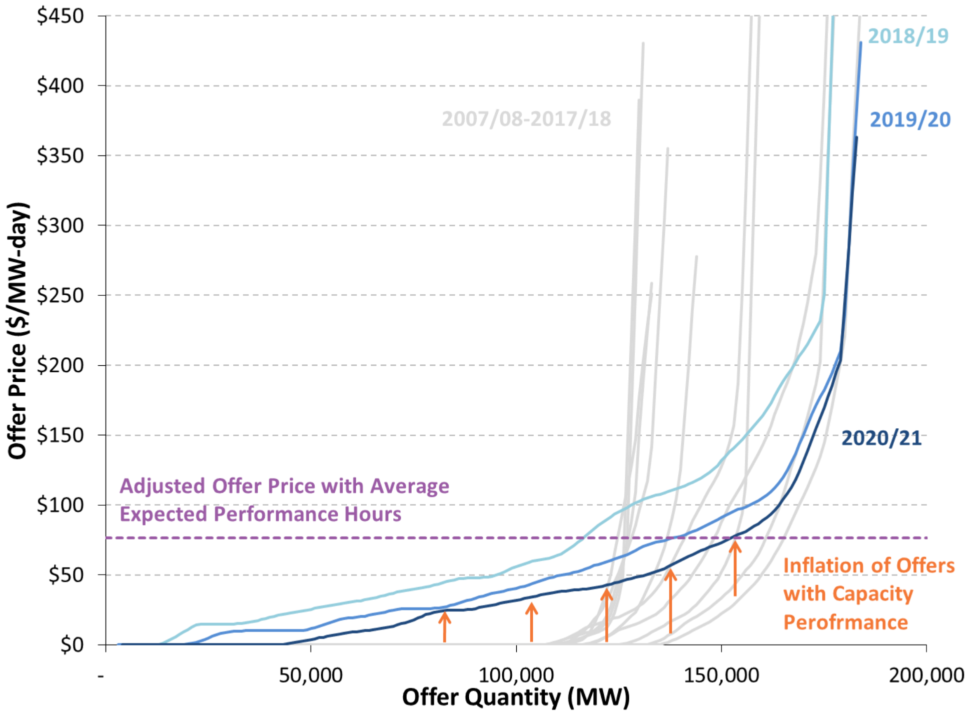
Following capacity shortfalls during the 2014 Polar Vortex, PJM developed the Capacity Performance construct to ensure that the RPM delivered the expected level of reliability. Capacity Performance created significantly stronger incentives for resources committed in the capacity auction to meet their 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

---

[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.

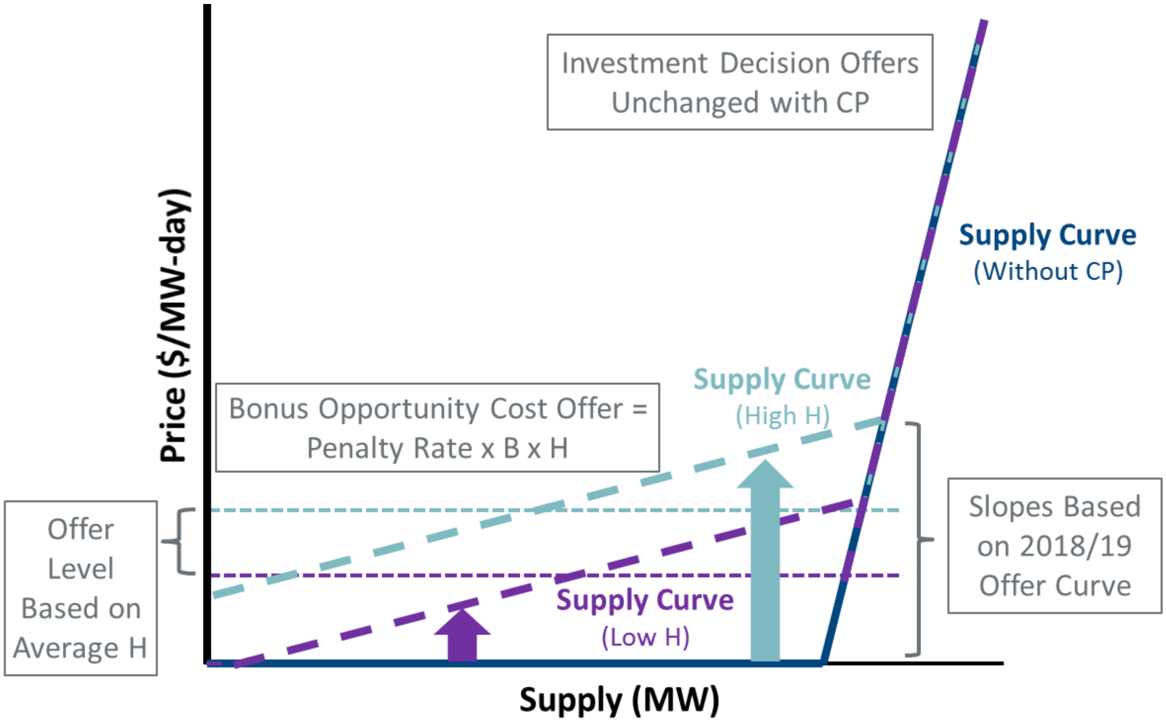
unavailable to operate to meet their obligations. For example, during the 2014 Polar Vortex, PJM had sufficient installed capacity to meet load but many plants were not available due to fuel supply or other operability constraints.

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]

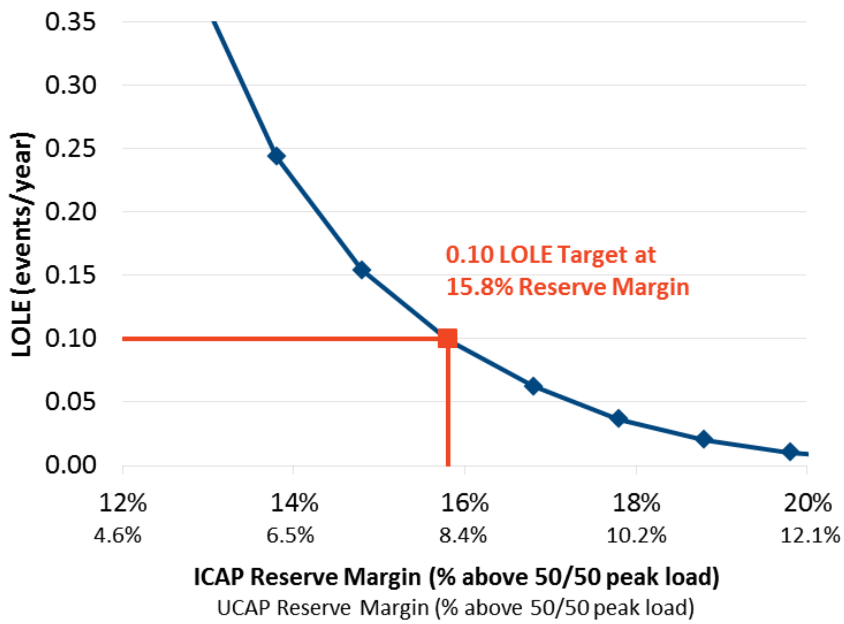
---

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

[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:

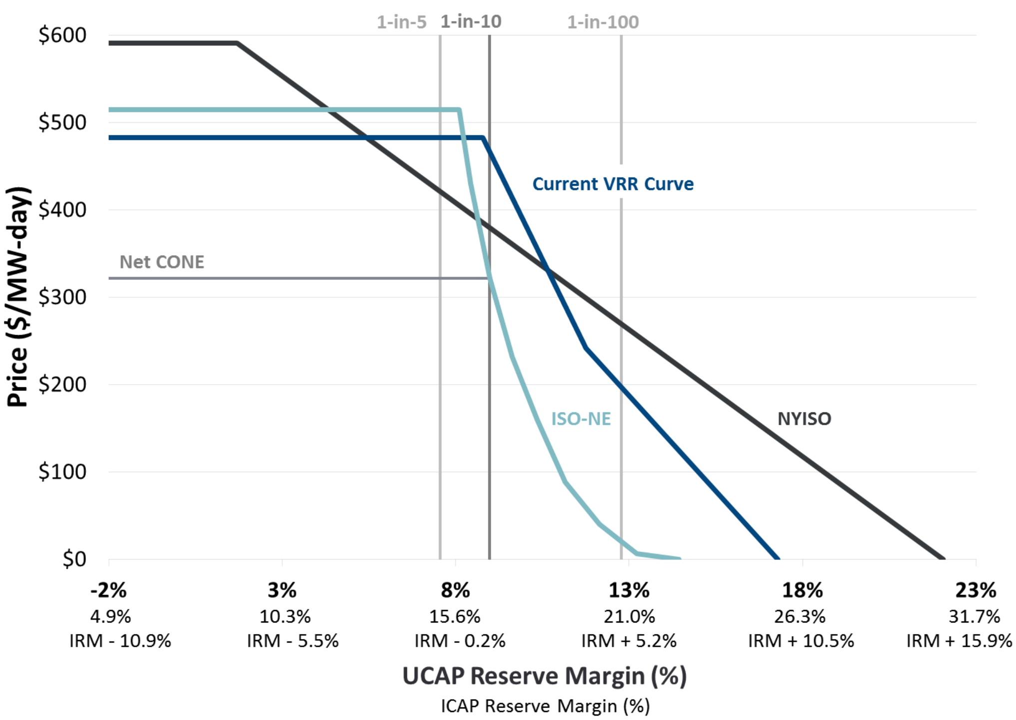
Average Parameter Values are from 2020/21 PJM Planning Parameters, see PJM (2017c).

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:

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.

---

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

---

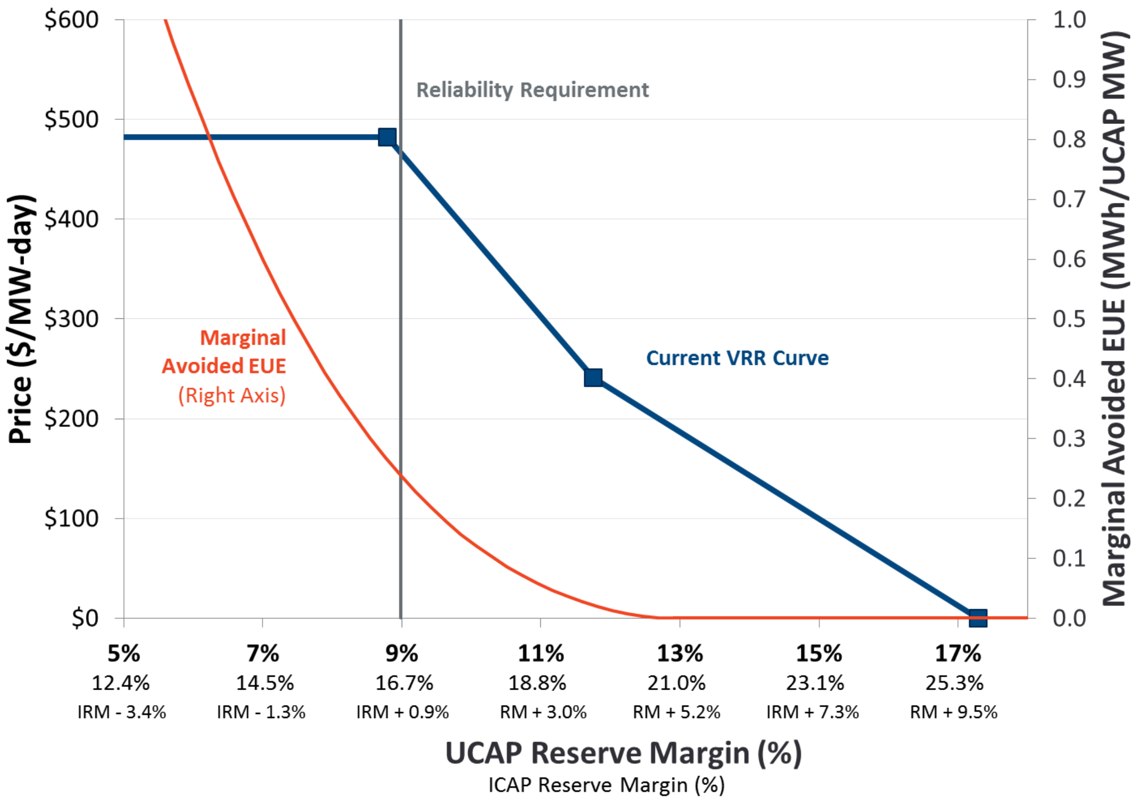
64 For example, see Pfeifenberger (2013).

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.

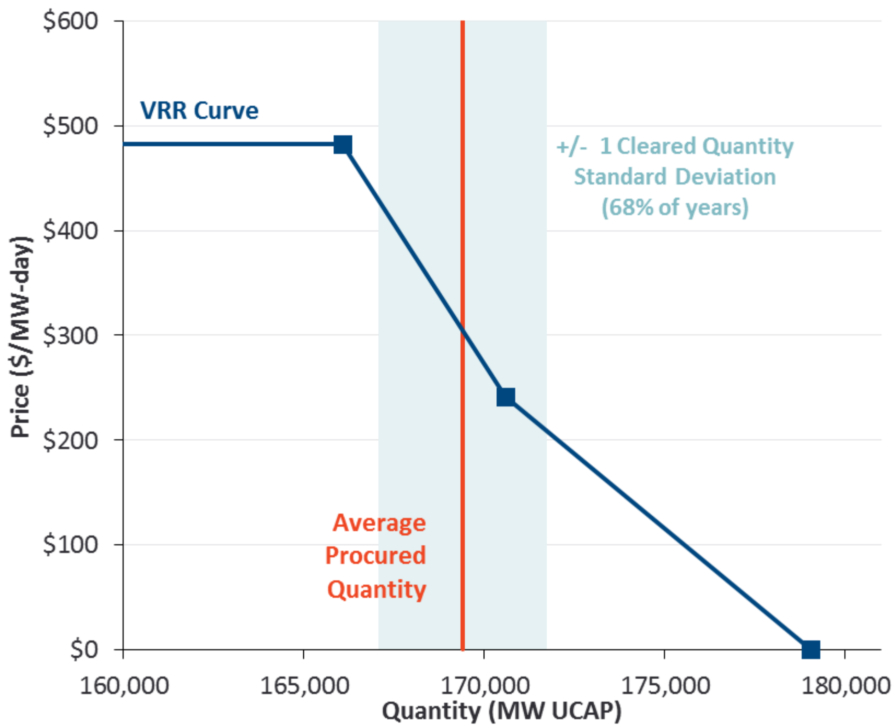
67 See Section OATT Attachment DD.16 PJM (2017h)

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) *($/MW-d)*	Standard Deviation of Price *($/MW-d)*	Frequency at Cap *(%)*	Average Cost (P × Q) *($mil)*	Average LOLE *(Ev/Yr)*	Average Excess (Deficit) *(IRM + X%)*	Reserve Margin Standard Deviation *(% ICAP)*	Frequency Below Reliability Requirement *(%)*	Frequency Below 1-in-5 *(%)*
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

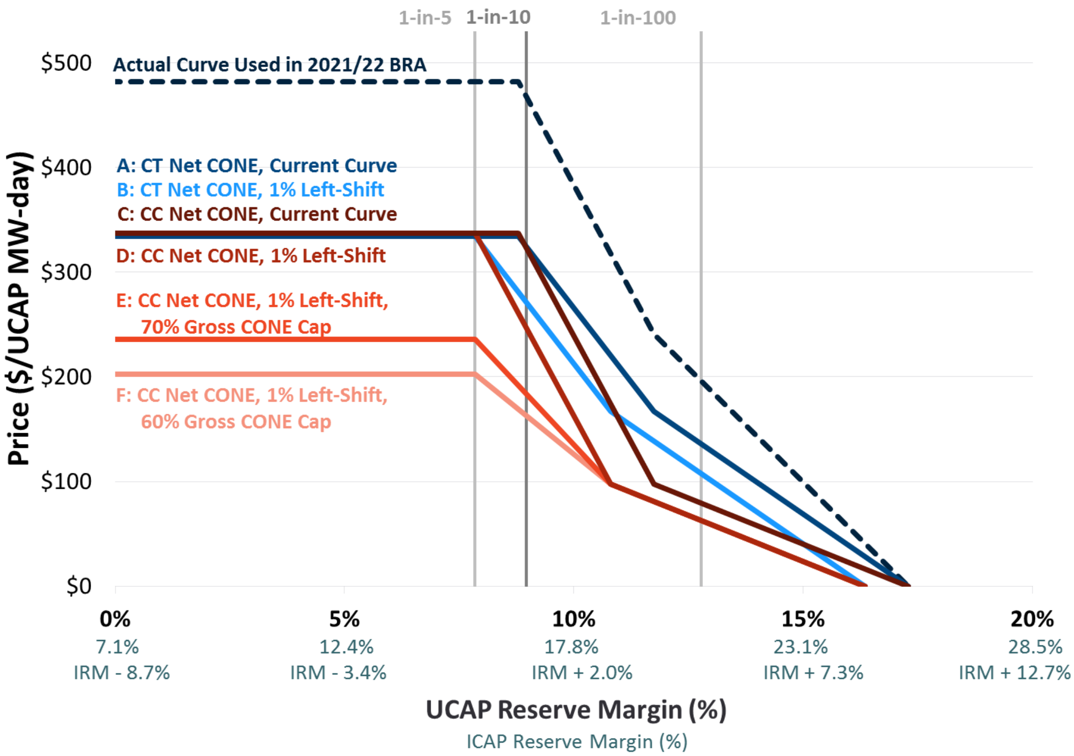
	Price and Procurement Costs				Reliability				
	Average Price (= Market Entry Price)	Standard Deviation of Price	Frequency at Cap	Average Cost (P × Q)	Average LOLE	Average Excess (Deficit)	Reserve Margin Standard Deviation	Frequency Below Reliability Requirement	Frequency Below 1-in-5
	($/MW-d)	*($/MW-d)*	*(%)*	*($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**.

---

[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]

---

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.

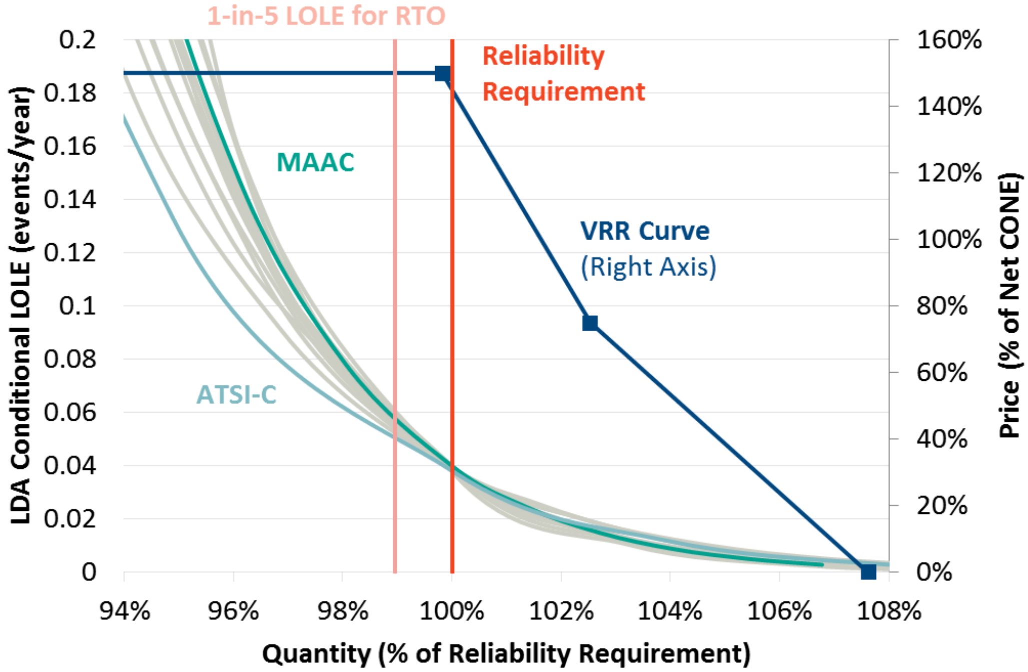
2. Locational Curve Price Cap and Shape

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.

---

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

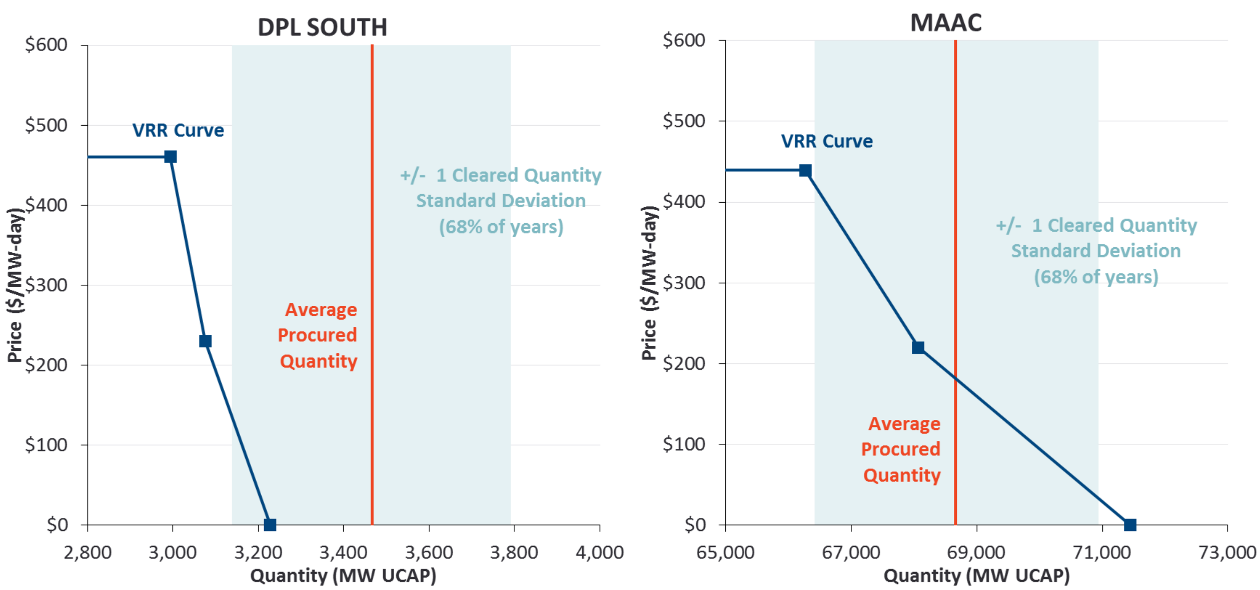
We also examine the width of the locational VRR curves compared to expected year-to-year fluctuation to the cleared supply (including imports) at the local level. In Figure 22, we show the

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.

---

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)	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	$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 <u>5% Higher</u> 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.

---

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]

---

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

Bibliography

Federal Energy Regulatory Commission (2014). Order Conditionally Accepting Tariff Revisions Subject to Compliance Filing, Issued November 28, 2014. Docket No. ER14-2940-000.

Federal Energy Regulatory Commission (2017). Order Accepting Filing, Issued October 6, 2017. Docket No. ER17-795-000.

ISO New England (2016). *FCA 11 MRI Base System-wide and Zonal Sloped Demand Curves*, October 4, 2016. Retrieved from: https://www.iso-ne.com/static-assets/documents/2016/09/a2_fca11_demand_curves.pdf

ISO New England, Inc., (2017). "RE: ISO New England Inc.; Filing of CONE and ORTP Updates," January 13, 2017. Docket No. ER17-795-000. Retrieved from: https://iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf

Monitoring Analytics (2014). State of the Market Reports. Available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014.shtml

Monitoring Analytics (2017). State of the Market Reports. Available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017.shtml

Newell, Samuel., J. Michael Hagerty, Johannes P. Pfeifenberger, Bin Zhou, Emily Shorin, Perry Fitz (2018). *PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, February 2018.

New York Independent System Operator (2017). *Manual 4: Installed Capacity Manual*, August 2017. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

Potomac Economics (2017). "Concept for Locational Capacity Pricing Based on Marginal Reliability Impacts and Costs," June 22, 2017. Retrieved from: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2017-06-22/SOM%20Recommendation%202013-1c%20re%20Capacity%20Pricing_ICAPWG_6-22-2017.pdf

Pfeifenberger, Johannes P., Samuel A. Newell, Robert Earle, Attila Hajos, and Mariko Geronimo (2008). *Review of PJM's Reliability Pricing Model (RPM)*, June 30, 2008. Retrieved from: http://brattle.com/system/publications/pdfs/000/004/728/original/Review_of_PJM's_Reliability_Pricing_Model_Pfeifenberger_et_al_Jun_30_2008.pdf?1378772125

Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, Attila Hajos, and Kamen Madjarov (2011). *Second Performance Assessment of PJM's Reliability Pricing Model: Market*

Results 2007/08 through 2014/15, August 26, 2011. Retrieved from: http://www.brattle.com/system/publications/pdfs/000/004/833/original/Second_Performance_Assessment_of_PJM's_Reliability_Pricing_Model_Pfeifenberger_et_al_Aug_26_2011.pdf?1378772133

Pfeifenberger, Johannes P., Kathleen Spees, Kevin Carden, and Nick Wintermantel (2013). Resource Adequacy Requirements: Reliability and Economic Implications, September 2013. Retrieved from: http://www.brattle.com/system/news/pdfs/000/000/618/original/Resource_Adequacy_Requirements_-_Reliability_and_Economic_Requirements.pdf?1392126844

Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, Ann Murray, and Ioanna Karkatsouli (2014). *Third Triennial Review of PJM's Variable Resource Requirement Curve,* May 15, 2014. Retrieved from: http://www.brattle.com/system/publications/pdfs/000/005/009/original/Third_Triennial_Review_of_PJM's_Variable_Resource_Requirement_Curve.pdf?1400252215

PJM Interconnection, L.L.C. (2005). "Summer 2005 PJM Reliability Assessment," June 7, 2005. Retrieved from: http://www.puc.state.pa.us/electric/pdf/Reliability/PJM_Summer_Reliability2005.pdf

PJM Interconnection, L.L.C. (2006). "Summer 2006 PJM Reliability Assessment," May 24, 2006. Retrieved from: http://www.puc.state.pa.us/electric/pdf/Reliability/PJM_Summer_Reliability2006.pdf

PJM Interconnection, L.L.C. (2007a). "2007 Load Forecast Report," January 2007. Retrieved from: http://www.pjm.com/-/media/planning/res-adeq/load-forecast/2007-load-report.ashx?la=en

PJM Interconnection, L.L.C. (2007b). "Summer 2007 PJM Reliability Assessment," May 30, 2007. Retrieved from: http://www.puc.state.pa.us/electric/pdf/Reliability/PJM_Summer_Reliability2007.pdf

PJM Interconnection, L.L.C. (2007c). "2007/08–2009/10 Planning Period Parameters," October 29, 2007. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/planning-period-parameters.ashx?la=en

PJM Interconnection, L.L.C. (2008a). "2008 Load Forecast Report," January 2008. Retrieved from: http://www.pjm.com/-/media/documents/reports/2008-load-report.ashx?la=en

PJM Interconnection, L.L.C. (2008b). "Summer 2008 PJM Reliability Assessment," June 12, 2008. Retrieved from: http://www.puc.state.pa.us/electric/pdf/Reliability/PJM_Summer_Reliability2008.pdf

PJM Interconnection, L.L.C. (2009a). "2009 Load Forecast Report," January 2009. Retrieved from: http://www.pjm.com/-/media/documents/reports/2009-pjm-load-report.ashx?la=en

PJM Interconnection, L.L.C. (2009b). "2012/2013 Planning Period Parameters," May 22, 2009. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2012-2013-rpm-planning-parameters.ashx?la=en

PJM Interconnection, L.L.C. (2009c). "Summer 2009 PJM Reliability Assessment," June 9, 2009. Retrieved from: http://www.puc.state.pa.us/electric/pdf/Reliability/Summer_Reliability_2009-PJM.pdf

PJM Interconnection, L.L.C. (2009d). "2011/2012 Planning Period Parameters," December 2, 2009. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2011-2012-rpm-bra-planning-parameters.ashx?la=en

PJM Interconnection, L.L.C. (2009e). "2010/2011 Planning Period Parameters," December 3, 2009. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2010-2011-rpm-planning-parameters.ashx?la=en

PJM Interconnection, L.L.C. (2009f). "A Review of Generation Compensation and Cost Elements in the PJM Markets," 2009. Retrieved from: http://www.pjm.com/~/media/committees-groups/committees/mrc/20100120/20100120-item-02-review-of-generation-costs-and-compensation.ashx

PJM Interconnection, L.L.C. (2010a). "2010 Load Forecast Report," January 2010. Retrieved from: http://www.pjm.com/-/media/documents/reports/2010-load-forecast-report.ashx?la=en

PJM Interconnection, L.L.C. (2010b). "2013/2014 Planning Period Parameters," May 17, 2010. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2013-2014-planning-period-parameters.ashx?la=en

PJM Interconnection, L.L.C. (2010c). "Summer 2010 PJM Reliability Assessment," May 20, 2010. Retrieved from: http://www.puc.state.pa.us/electric/pdf/Reliability/Summer_Reliability_2010-PJM.pdf

PJM Interconnection, L.L.C. (2011a). "2011 Load Forecast Report," January 2011. Retrieved from: http://www.pjm.com/-/media/library/reports-notices/load-forecast/2011-pjm-load-report.ashx?la=en

PJM Interconnection, L.L.C. (2011b). "2014/2015 Planning Period Parameters," April 8, 2011. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-bra-planning-parameters-2014-2015.ashx?la=en

PJM Interconnection, L.L.C. (2011c). "Summer 2011 PJM Reliability Assessment," June 9, 2011. Retrieved from: https://www.puc.state.pa.us/electric/pdf/Reliability/Summer_Reliability_2011-PJM.pdf

PJM Interconnection, L.L.C. (2012a). "2012 Load Forecast Report," January 2012. Retrieved from: http://www.pjm.com/-/media/library/reports-notices/load-forecast/2012-pjm-load-report.ashx?la=en

PJM Interconnection, L.L.C. (2012b). "2015/2016 Planning Period Parameters," May 22, 2012. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2015-2016-planning-period-parameters.ashx?la=en

PJM Interconnection, L.L.C. (2012c). "Summer 2012 PJM Reliability Assessment," June 7, 2012. Retrieved from: https://www.puc.state.pa.us/electric/pdf/Reliability/Summer_Reliability_2012-PJM.pdf

PJM Interconnection, L.L.C. (2013a). "2013 Load Forecast Report," January 2013. Retrieved from: http://www.pjm.com/-/media/library/reports-notices/load-forecast/2013-load-forecast-report.ashx?la=en

PJM Interconnection, L.L.C. (2013b). "Summer 2013 PJM Reliability Assessment," June 6, 2013. Retrieved from: http://www.puc.state.pa.us/Electric/pdf/Reliability/Summer_Reliability_2013-PJM.pdf

PJM Interconnection, L.L.C. (2014a). "2014 Load Forecast Report," January 2014. Retrieved from: http://www.pjm.com/-/media/library/reports-notices/load-forecast/2014-load-forecast-report.ashx?la=en

PJM Interconnection, L.L.C. (2014b). "Summer 2014 PJM Reliability Assessment," June 2014. Retrieved from: http://www.puc.pa.gov/Electric/pdf/Reliability/Summer_Reliability_2014-PJM.pdf

PJM Interconnection, L.L.C. (2014c). "2016/2017 Planning Parameters," June 4, 2014. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2016-2017-planning-period-parameters.ashx?la=en

PJM Interconnection, L.L.C. (2014e). "2017/2018 Planning Parameters," June 4, 2014. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2017-2018-planning-period-parameters.ashx?la=en

PJM Interconnection, L.L.C. (2014f). "Revisions to the PJM Open Access Transmission Tariff," September 25, 2014. Docket No. ER14-2940-000.

PJM Interconnection, L.L.C. (2015a). "2015 Load Forecast Report," January 2015. Retrieved from: http://www.pjm.com/-/media/library/reports-notices/load-forecast/2015-load-forecast-report.ashx?la=en

PJM Interconnection, L.L.C. (2015b). "Summer 2015 PJM Reliability Assessment," June 2015. Retrieved from: http://www.puc.pa.gov/Electric/pdf/Reliability/Summer_Reliability_2015-PJM.pdf

PJM Interconnection, L.L.C. (2015c). "Capacity Performance Transition Incremental Auctions Rules, Schedule and Planning Parameters," July 28, 2015. Retrieved from: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2018-cp-transition-incremental-auctions-rules-schedule-planning-parameters.ashx

PJM Interconnection, L.L.C. (2015d). "2018/2019 Planning Parameters," August 27, 2015. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2018-2019-bra-planning-parameters.ashx?la=en

PJM Interconnection, L.L.C. (2015e). "Historical Performance Assessment Hours," November 16, 2015. Retrieved from: http://www.pjm.com/-/media/committees-groups/committees/elc/postings/historical-performance-assessment-hours.ashx?la=en

PJM Interconnection, L.L.C. (2016a). "2016 Load Forecast Report," January 2016. Retrieved from: http://www.pjm.com/-/media/library/reports-notices/load-forecast/2016-load-report.ashx?la=en

PJM Interconnection, L.L.C. (2016b). "Summer 2016 PJM Reliability Assessment," June 2016. Retrieved from: http://www.puc.state.pa.us/Electric/pdf/Reliability/Summer_Reliability_2016-PJM.pdf

PJM Interconnection, L.L.C. (2016c). "2019/2020 Planning Parameters," June 10, 2016. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2019-2020-bra-planning-parameters.ashx?la=en

PJM Interconnection, L.L.C. (2017a). "2017 Load Forecast Report," January 2017. Retrieved from: http://www.pjm.com/-/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx?la=en

PJM Interconnection, L.L.C. (2017b). "Final CP Market Seller Offer Cap Values", January 9, 2017. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-final-cp-market-seller-offer-cap-values.ashx?la=en

PJM Interconnection, L.L.C. (2017c). "2020/2021 Planning Parameters," May 23, 2017. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-bra-planning-period-parameters.ashx?la=en

PJM Interconnection, L.L.C. (2017d). "2020/2021 RPM Base Residual Auction Results," May 23, 2017. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx?la=en

PJM Interconnection, L.L.C. (2017e). "Summer 2017 PJM Reliability Assessment," June 2017. Retrieved from: http://www.puc.state.pa.us/Electric/pdf/Reliability/Summer_Reliability_2017-PJM.pdf

PJM Interconnection, L.L.C. (2017f). "PJM Manual 18: PJM Capacity Market," July 27, 2017. Retrieved from: http://www.pjm.com/-/media/documents/manuals/m18.ashx

PJM Interconnection, L.L.C. (2017g). *PJM Manual 18: PJM Capacity Market.* Revision 38, Effective July 27, 2017. Retrieved from: http://www.pjm.com/~/media/documents/manuals/m18.ashx

PJM Interconnection, L.L.C. (2017h) PJM Open Access Transmission Tariff. Effective October 1, 2017. Retrieved from: http://www.pjm.com/directory/merged-tariffs/oatt.pdf

PJM Interconnection, L.L.C. (2017i). "2017 PJM Reserve Requirement Study," October 12, 2017. Retrieved from: http://wired.pjm.com/-/media/committees-groups/committees/mc/20171026/20171026-item-03-2017-irm-study.ashx

PJM Interconnection, L.L.C. (2018). "2021/2022 Planning Parameters," February 01, 2018. Retrieved from: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-bra-planning-period-parameters.ashx?la=en

Weitzman, Martin L. (1974), "Prices vs. Quantities", *The Review of Economic Studies* 41(4), October 1974, pp. 477–491.

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.

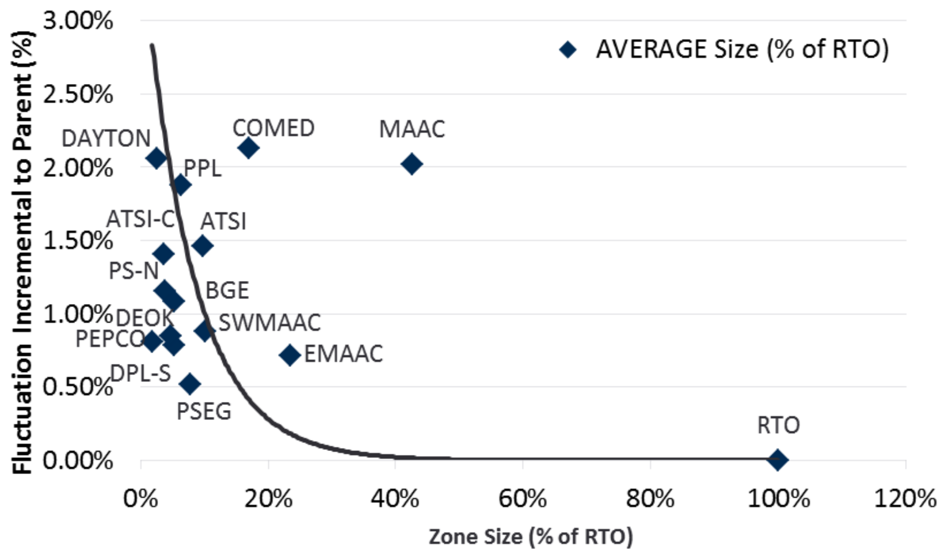
Table 22
Fluctuations in Reliability Requirement

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

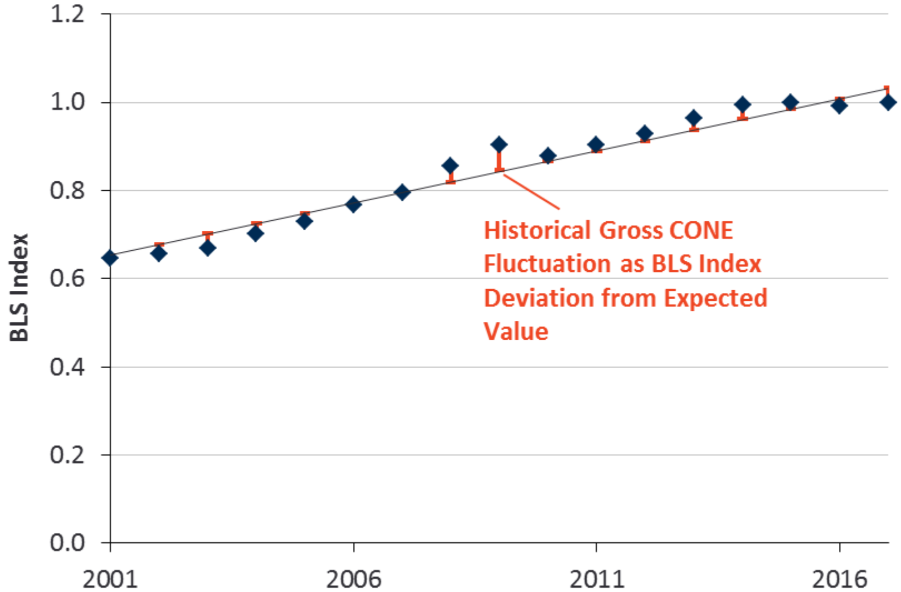


Sources and Notes:
Zone Size calculated based on average reliability requirement from 2007/08–2020/21. Reliability requirement created using a combination of BRA input parameters and forecasted peak load. See PJM Planning Period Parameters for the years 20072017.

C. Administrative Net CONE

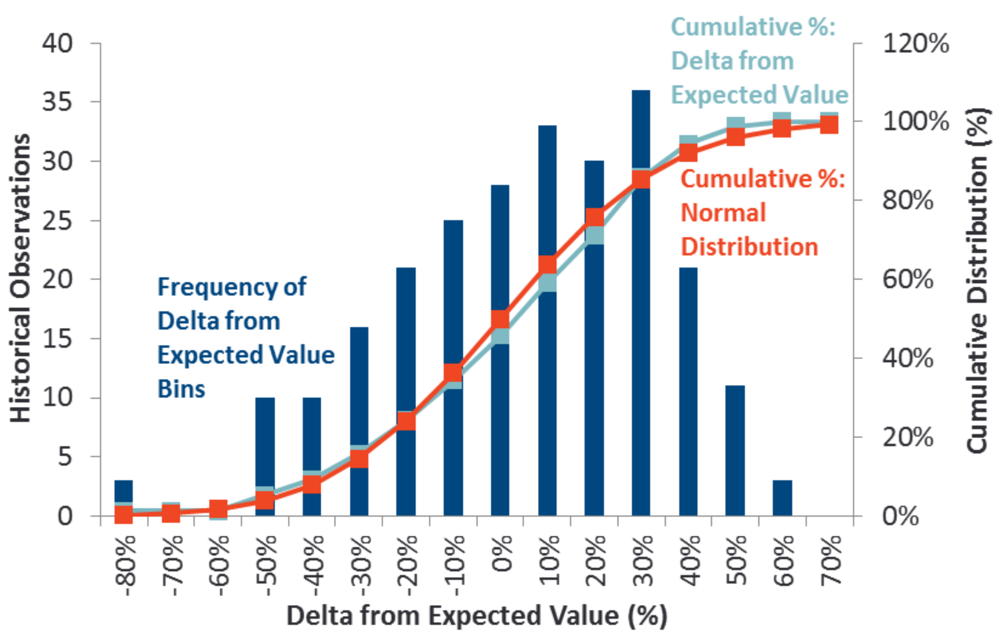
We develop Net CONE fluctuations as the sum of fluctuations to Gross CONE and a 3-year average E&AS fluctuation. We model Gross CONE fluctuations of 3.1% based on deviations away from a long-term trend in the composite BLS index PJM uses to inflate Gross CONE year to year, as illustrated in Figure 24. 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

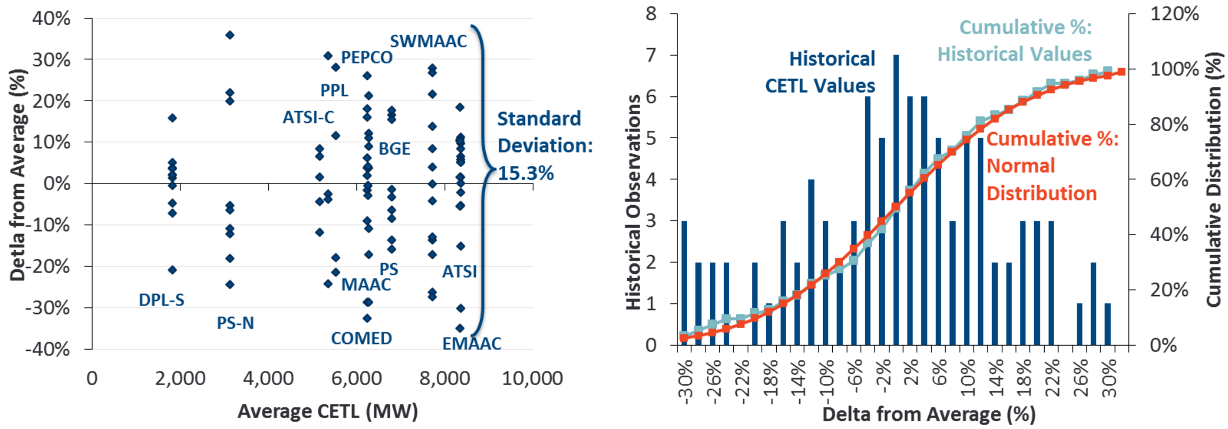
LDA	Base Assumptions from 2020/21				Standard Deviation of Fluctuation Components			
	Expected Gross CONE	Expected E&AS	Expected Net CONE	Net CONE Fluctuations	Gross CONE	One-Year E&AS	Three-Year E&AS	Net CONE
	($/MW-d)	*($/MW-d)*	*($/MW-d)*	*($/MW-d)*	*(%)*	*(%)*	*(%)*	*(%)*
RTO	$394	$101	$293	$21	3.1%	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				Standard Deviation as % of 2020/21 RR			
	Supply *(MW)*	CETL *(MW)*	Reliability Requirement *(MW)*	Net Supply *(MW)*	Supply *(%)*	CETL *(%)*	Reliability Requirement *(%)*	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.

---

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

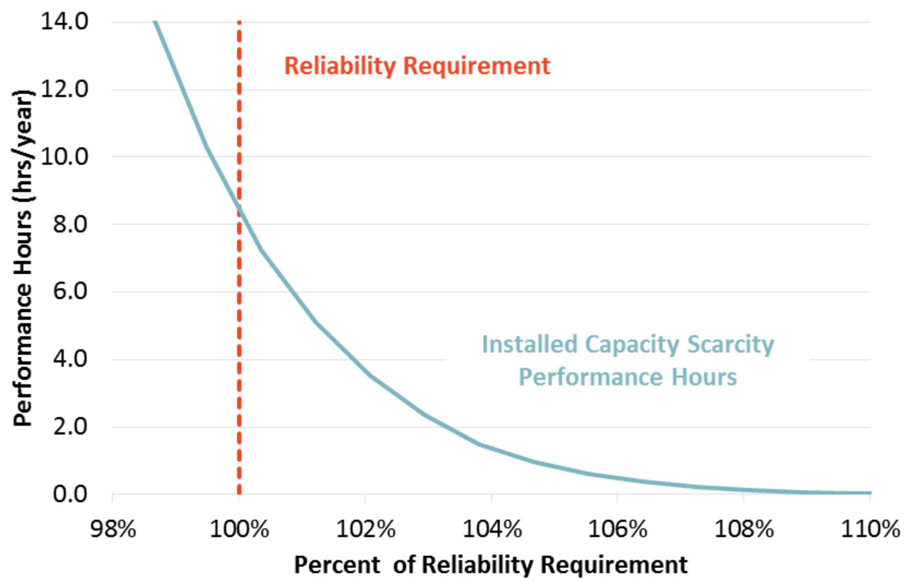
---

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



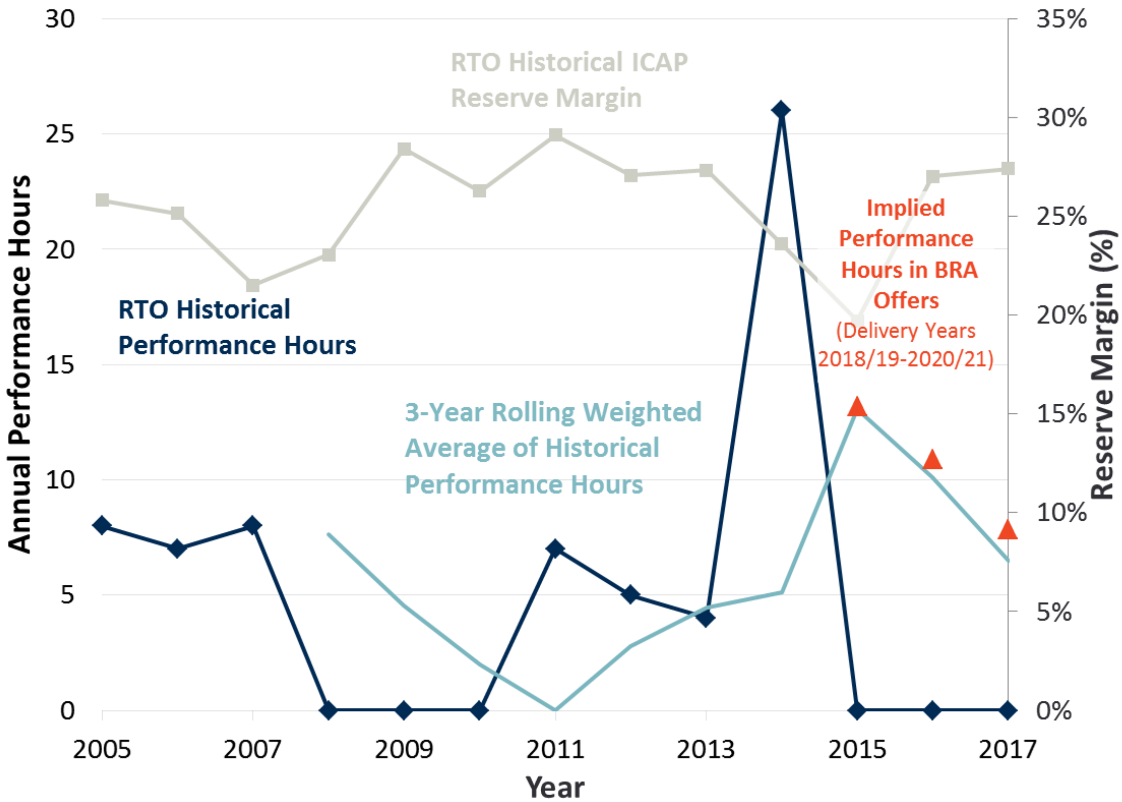
Source:
Results from PJM Reliability Model provided by PJM staff.

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

[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

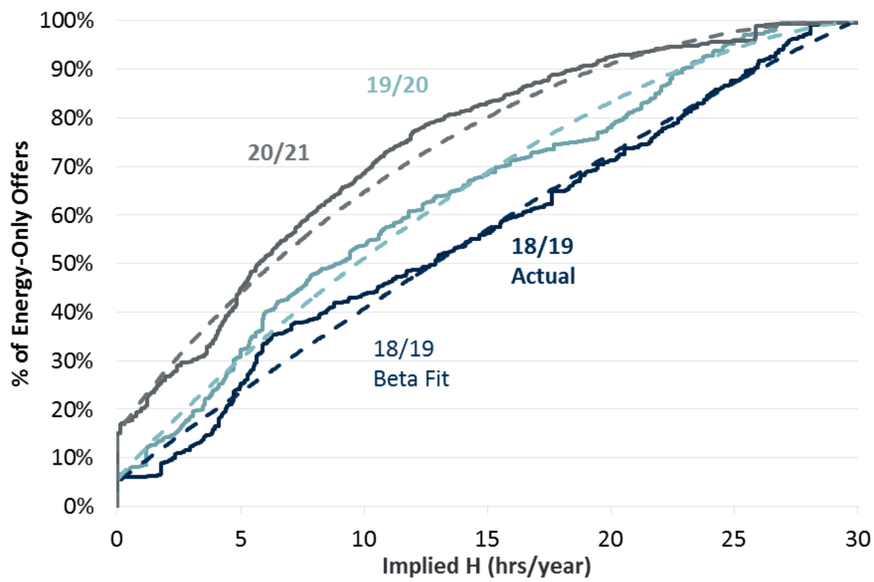
---

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.

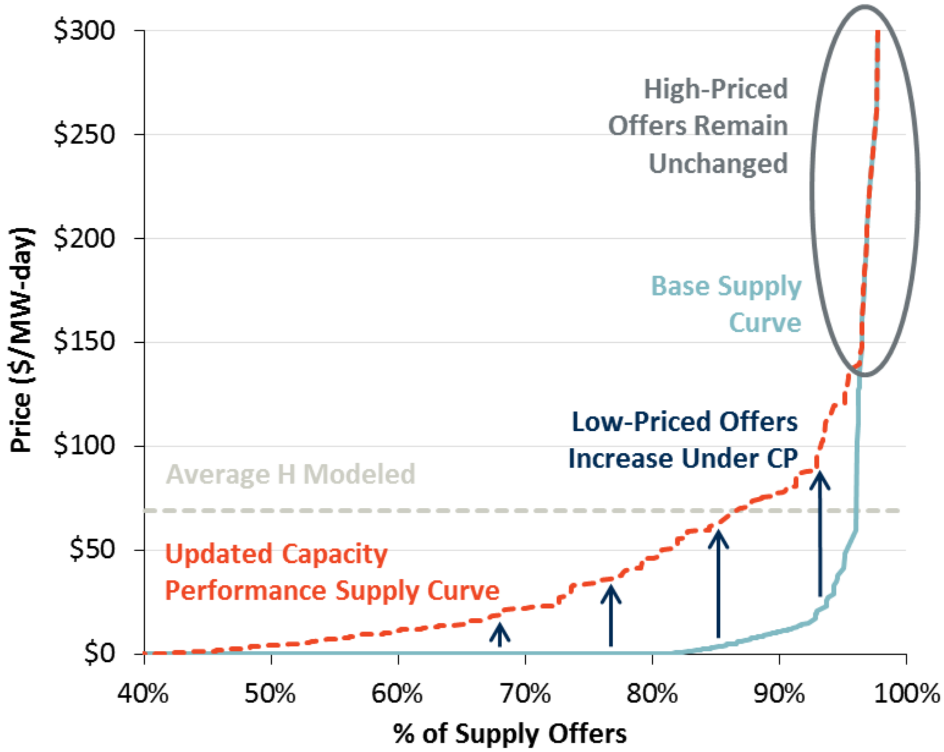
B. Supply Curves Under Capacity Performance

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



*Sourc*e 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.