
Third Triennial Review of PJM's Variable Resource Requirement Curve

PREPARED FOR



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Executive Summary

The Brattle Group has been commissioned by PJM Interconnection, L.L.C. (PJM) to evaluate the parameters and shape of the administrative Variable Resource Requirement (VRR) curve used to procure capacity under the Reliability Pricing Model (RPM), as required periodically under the PJM Tariff.¹ Consistent with the review scope specified in PJM's Tariff, we evaluate three key elements of RPM: (1) the Cost of New Entry (CONE) parameter; (2) the methodology for determining the Net Energy and Ancillary Services (E&AS) Revenue Offset; and (3) the shape of the VRR curve. For each of these elements, we evaluate how well the current design supports RPM's resource adequacy and other design objectives, and provide recommendations on how this performance can be improved.

A. COST OF NEW ENTRY

The administrative Gross CONE value reflects the net revenues a new generation resource needs to earn to enter the market and recover its capital investment and annual fixed costs. Gross CONE is the starting point for estimating the *Net* CONE. Net CONE is defined as the operating margins that a new resource would need to earn in the capacity market, after netting margins earned in the E&AS markets. Accurate Net CONE estimates are critical to RPM performance because they provide the benchmark prices against which administratively-determined system and local VRR curves are defined. Over- or under-estimated Net CONE values would result in either over- or under-procuring capacity relative to the quantity needed to satisfy PJM's resource adequacy standard.

To develop updated CONE values applicable for the 2018/19 planning year, we partnered with the engineering services firm Sargent & Lundy. We recommended that PJM adopt these updated CONE values based on bottom-up engineering cost estimates for simple-cycle combustion turbine (CT) and combined cycle (CC) generation plants. We also review the methodology to calculate "levelized" annual costs, indices used to update CONE between CONE studies, and the choice of reference technology. Our principal recommendations regarding CONE for PJM's and stakeholders' further consideration are:

- 1. Adopt updated CONE estimates.** Our updated level-nominal CONE estimates are within +/- 11% of PJM's 2017/2018 parameters (escalated by 3% to 2018 dollars), depending on CONE Area and technology. These estimates are based on plant specifications consistent with predominant industry practice and to conform to environmental requirements, infrastructure availability, and economic factors. Cost estimates incorporate current costs

¹ To date, PJM has required a triennial review of these parameters; in the future the review will be required only once every four years. See PJM (2014b), Section 5.10.a.iii.

of equipment, materials, and labor. Our levelized CONE calculation also incorporates an updated cost of capital estimate for merchant generation projects, which we estimate at 8.0% on an after-tax weighted average cost of capital (ATWACC) basis. While we present a summary of our updated CONE estimates in this report, full details are included in our separate, concurrently-released report, “Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM with June 1, 2018 Online Date.”

- 2. Adopt level-real CONE values.** We recommend replacing PJM’s level-nominal calculation (yielding annual CONE values that are assumed to stay constant for 20 years in actual, nominal dollars) with a level-real calculation (which would yield annual CONE values that are assumed to increase with inflation over time). This alternative level-real calculation is consistent with the approach used by New York Independent System Operator (NYISO) and ISO New England (ISO-NE), and we believe it is more representative of investors’ expected recovery of capital and fixed costs over the long term. Level-real reflects a market view in which capital recovery remains constant in real (current) dollar terms as a result of two approximately offsetting factors: (a) the rate of technology cost escalation for new plants (a rate somewhat higher than inflation), and (b) the rate of performance improvement of future entrants that will tend to erode the future capacity market prices earned by today’s entrants. Adopting this recommendation would reduce CONE values for the RPM delivery year by approximately 15%. For example, our updated CONE estimates for CTs and CCs in the Eastern Mid-Atlantic Area Council (Eastern MAAC or EMAAC) are \$127,300/MW-yr and \$173,100/MW-d in level-real terms, compared to our estimates of \$150,000 and \$203,900 in level-nominal terms.
- 3. Consider replacing the Handy-Whitman Index (H-W) for annual updates.** To escalate CONE values annually between CONE studies, we recommend that PJM consider replacing the Handy-Whitman “Other” index with a weighted composite of wage, materials, and turbine cost indices from the Bureau of Labor Statistics (BLS). We believe such an approach would more accurately reflect industry cost trends that are the underlying drivers of changes to CONE.
- 4. Consider adopting the average of CC and CT Net CONE values defining the VRR curve.** Rather than relying only on CT Net CONE estimates for defining the VRR curve, we recommend that PJM consider setting Net CONE based on the average of CC and CT Net CONE estimates. This would recognize that CC plants are the predominant technology under development by merchant generators (which increases the accuracy of Gross CONE estimates), while avoiding a complete switch away from the currently-defined CT reference technology. In the short term, the average of CC and CT Net CONE would be lower than a CT-based net CONE (if no other changes were made), or may be slightly higher or lower (if all of our recommended changes to the E&AS methodology are adopted). In the long-term our recommended approach will help stabilize Net CONE values under fluctuating market conditions and estimation errors that differently impacts CCs and CTs.

5. **Align CONE Areas more closely to modeled Locational Deliverability Areas (LDAs).²** We recommend that PJM consider revising the definitions of CONE Areas to more closely align with the modeled LDAs, by: (a) using the *CONE Area 3: Rest of PJM* estimate for the system-wide VRR curve (rather than the current fixed value adopted in settlement); (b) using the *CONE Area 4: Western MAAC* estimate for the MAAC VRR curve (rather than taking the minimum of sub-LDA numbers); and (c) combining *CONE Area 5: Dominion* into *CONE Area 3: Rest of PJM*, given that the Area 5 estimate has not been used to date. The result would be to develop a total of only four Gross CONE estimates in future studies, one for each of the four permanent LDAs.
6. **Consider introducing a test for a separate Gross CONE for small LDAs.** We also recommend that PJM introduce a test to determine whether smaller LDAs should have a separate Gross CONE estimate. In general, such a separate estimate would only be needed if the small LDA is persistently import-constrained, shows little evidence of potential for new entry, and shows evidence of structurally higher entry costs (e.g., because the reference technology cannot be built there).

B. NET ENERGY AND ANCILLARY SERVICE REVENUE OFFSET

As noted above, the E&AS revenue offset is intended to estimate the net revenues (or operating margins) the reference resource would earn from energy and ancillary services markets. The E&AS offset is subtracted from the estimated Gross CONE value, yielding the Net CONE parameter used for setting VRR curve prices. We evaluate PJM's historical E&AS offset estimates by comparing against the actual E&AS margins earned by generation units similar to the reference resources, and find that PJM's historical estimates are over-estimated for CCs in all locations and over-estimated for CTs in the Southwestern Mid-Atlantic Area Council (SWMAAC). We also compare the historical three-year average E&AS estimate, from which PJM's current Net CONE parameter is estimated, to an indicative forward-looking E&AS estimate based on futures prices for the RPM delivery year and find them to be very different for the CC. Finally, we find that the locations used for estimating E&AS margins are not well aligned with the LDAs for which VRR curves are defined. As a result, our principal recommendations for further consideration by PJM and its stakeholders are:

² Note that the current CONE Areas include the following load zones: (1) EMAAC includes Atlantic City Electric Company (AECO), Delmarva Power and Light (DPL), Jersey Central Power and Light Company (JCPL), PECO Energy Company (PECO), Public Service Enterprise Group (PSEG), and Rockland Electric Company (RECO); (2) SWMAAC includes Baltimore Gas and Electric Company (BGE) and Potomac Electric Power Company (PepCo); (3) Rest of RTO includes American Electric Power (AEP), Allegheny Power System (APS), American Transmission Systems, Inc (ATSI), Commonwealth Edison (ComEd), Dayton Power and Light Company (Dayton), Duke Energy Ohio/Kentucky (DEOK), and Duquesne Lighting Company (Duquesne); (4) WMAAC includes Metropolitan Edison Company (MetEd), Pennsylvania Electric Company (PenElec), and Pennsylvania Power and Light Company (PPL). LDA detailed definitions and structure in PJM (2014a).

- 1. Calibrate historical E&AS estimates to reflect plant actuals.** We recommend further investigating why PJM's simulated historical E&AS estimates exceed actual margins of CCs in all areas by roughly \$40,000/MW-yr and by roughly \$25,000/MW-yr for CTs in SWMAAC. Given the large discrepancies, we recommend that PJM compile a more detailed set of plant-specific cost and revenue data for representative units that can be used for such a calibration, and then adjust its historical simulation approach to develop E&AS numbers that are as reflective as possible of these actual plant data in each location. This adjustment would require identifying and accounting for factors that may be depressing actual net revenues below simulated levels, such as operational constraints, heat rate issues, differences in variable and commitment costs, or fuel availability. This analysis would inform how to develop more realistic simulations of E&AS margins, and avoid overstating E&AS offsets and understating Net CONE values, which risks procuring less capacity than needed to meet PJM's resource adequacy objectives. To allow flexibility in this calibration exercise, we also recommend that PJM consider eliminating Tariff language specifying an exact ancillary service (A/S) adder and variable operations and maintenance (VOM) cost assumption.
- 2. Develop a forward-looking estimate of Net E&AS revenues.** An E&AS offset based on three years of historical prices can be easily distorted by anomalous market conditions that are not representative of what market participants expect in the future RPM delivery year. The threat of significant distortions due to unusual historical market conditions has increased with PJM's new shortage pricing rules that will magnify the impact of shortages. For example, unusual weather or fuel market conditions can cause prices to spike, increasing E&AS revenues beyond what a generation developer would expect to earn in the future under more typical weather conditions. Historical prices are also 4 to 6 years out of date relative to delivery period corresponding to a three-year forward Base Residual Auction (BRA) and, therefore, may not be a good indicator of future market conditions. For these reasons, we recommend that PJM evaluate options for incorporating futures prices for fuel and electricity into this analysis, similar to the stakeholder-supported approach proposed to the Federal Energy Regulatory Commission (FERC) by ISO-NE. Currently, such a forward-looking E&AS approach would likely produce results similar to three-year historical approach for the CT, but substantially below the historical approach for the CC (resulting in a similar CT Net CONE, but an increased CC Net CONE).
- 3. Align E&AS offset and Net CONE calculations more closely to modeled LDAs.** The current approach calculates E&AS offsets based on prices in a single tariff-designated energy zone for each CONE Area. As a result, the E&AS offset that is applied to a specific LDA may not be calculated based on prices in that LDA, but on prices in the parent LDA, a sub-LDA, or an adjacent LDA, none of which would provide an accurate E&AS estimate for the LDA and thus may cause under- or over-stated Net CONE values. We recommend that each LDA's E&AS offset be estimated based on prices within that LDA. For large LDAs that cover many zones, such as the Regional Transmission Organization (RTO) and Mid-Atlantic Area Council (MAAC), the E&AS offset could be based on an

injection-weighted generation bus average locational marginal price (LMP) across the LDA, or an average of zone-level E&AS estimates weighted by the quantity of RPM generation offers from each zone in the last BRA. This more accurate approach would increase CONE for CT plants in PSEG, PSEG North, PepCo, and MAAC, while decreasing it in American Transmission Systems, Inc. (ATSI), ATSI-Cleveland (ATSI-C), and Delmarva Power and Light-South (DPL-South), by roughly \$4,000-6,000/MW-yr based on 2017/2018 RPM parameters.

- 4. Consider imposing the parent-LDA Net CONE value as a minimum for sub-LDA Net CONE values.** We recommend that PJM consider imposing a minimum Net CONE for sub-LDAs at the parent-LDA Net CONE value, either for all LDAs or at least for medium-sized or small LDAs (*i.e.*, for all LDAs smaller than MAAC or EMAAC). This recommendation would safeguard against errors and associated under-procurement in small LDAs. Such errors are more likely to occur in small LDAs, such as SWMAAC, which may have idiosyncratic conditions and small sample sizes for calibrating CONE and E&AS estimates, and where under-procurement has disproportionately high reliability consequences. Even if Net CONE were truly lower in a small LDA, imposing a “parent-minimum” constraint would avoid down-shifting the VRR curve and offsetting the locational investment signals created by E&AS prices. This recommendation could increase Net CONE in some modeled LDAs (*e.g.*, by approximately \$13,000/MW-yr in SWMAAC and PepCo under 2017/18 parameters) but likely would have no incremental effect if our other E&AS recommendations were adopted. If PJM and stakeholders decide not to pursue this recommendation, it would at least be necessary to carefully investigate E&AS and CONE estimates whenever Net CONE values in import-constrained LDAs are substantially below the Net CONE estimates of the parent LDA, such as in SWMAAC where low historical Net CONE estimates were caused by inaccurately high E&AS estimates.

C. THE VARIABLE RESOURCE REQUIREMENT CURVE

In our review of the VRR curve, we rely heavily on probabilistic simulations of RPM auction outcomes using a Monte Carlo simulation model that estimates the distribution of capacity market price and quantity outcomes under a particular demand curve shape. We use these results to determine whether the existing VRR curves could meet PJM’s resource adequacy and other RPM design objectives. Our probabilistic simulation model differs from the model iterations used to support the development and prior evaluations of the VRR curve in that it: (a) simulates RPM auctions at both the RTO and LDA levels; (b) incorporates realistic supply curve shapes developed from historical BRA offer data; and (c) relies on realistic “shocks” to supply, demand, and transmission informed by and calibrated based on actual historical market conditions and auction outcomes.

We base our probabilistic simulations on long-term equilibrium market conditions (not current or near-term market conditions) under which total supply adjusts until the long-term average

price over all draws equals Net CONE. We estimate a distribution of price and quantity outcomes by applying realistically-sized “shocks” to supply, demand, administrative Net CONE, and transmission parameters, around the expected value. We translate the resulting distributions of clearing prices and quantities into a set of metrics for evaluating RPM performance against four objectives. These objectives, determined in consultation with PJM staff, are:

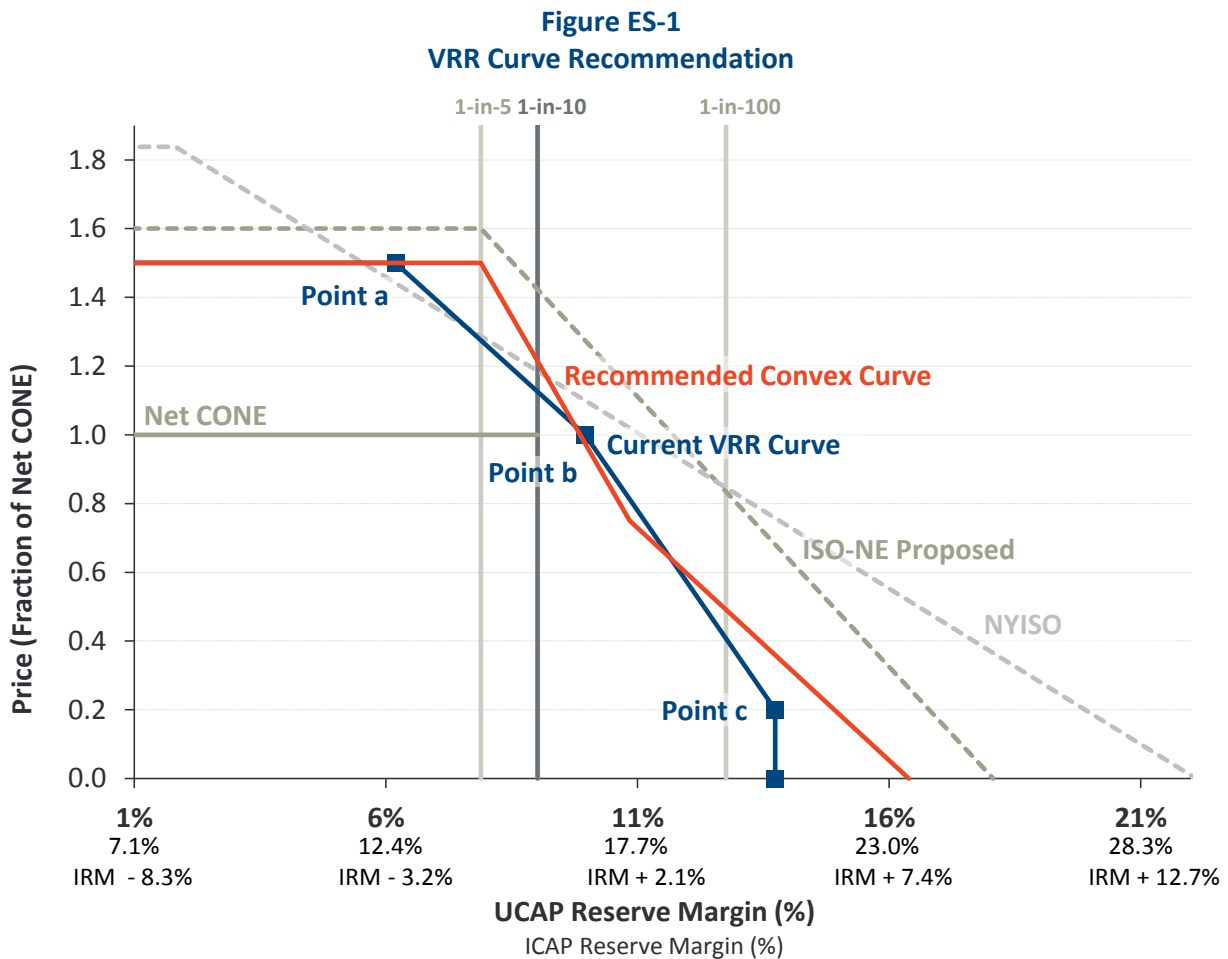
- (1) Achieve an average Loss-of-Load Event (LOLE) of one event in ten years for the system, and a 1-in-25 conditional LOLE in all LDAs (LOLEs are calculated as a function of cleared quantities, based on the results of PJM’s reliability studies);
- (2) Rarely fall below 1-in-5 LOLE, which is approximately 1% below PJM’s Installed Reserve Margin (IRM) target, the point at which PJM is authorized to conduct backstop procurement auctions under certain conditions;
- (3) Be resilient to changes in market conditions, administrative parameters, and uncertainties, but without relying on costly over-procurement to eliminate all potential risks; and
- (4) Mitigate price volatility and susceptibility to the exercise of market power.

We find that the existing VRR curve would not satisfy these performance objectives and fail to achieve resource adequacy objectives at both the system-level and the local level on a long-term average basis. For example, we estimate that the average LOLE across all years would be 0.12 (*i.e.*, 0.12 events per year or 1.2 events in 10 years) at the system level, with reliability falling below 1-in-5 LOLE in 20% of all years. These results vary across a range of modeling assumptions, RPM parameter values, and economic shocks that might reasonably be encountered, with objectives being met in some scenarios but widely missed in others. These findings differ from RPM market experience to date because we model long-term equilibrium conditions under which existing surplus resources and low-cost sources of new capacity are exhausted. To improve RPM performance, we recommend the following VRR Curve revisions:

1. **Right-shift point “a”.** We recommend that PJM right-shift point “a” (the highest-quantity point at the price cap) to a quantity at 1-in-5 LOLE (at approximately IRM-1%). This change would significantly improve reliability outcomes by providing stronger price signals when supplies become scarce, without right-shifting the entire distribution of expected reserve margins. This change would not increase long-term average prices, which would be determined by the market, based on the true Net CONE developers incur to develop new resources. Right-shifting point “a” would also make the VRR curve more consistent with PJM’s current reliability backstop auction trigger at IRM-1%, such that PJM would procure all available resources through the BRA before any such backstop auction could be triggered.
2. **Stretch the VRR Curve into a convex shape.** We recommend that PJM consider adopting the convex shape (*i.e.*, less steep at higher reserve margins) as illustrated in Figure ES-1, with its parameters tuned such that the curve will meet the 1-in-10 reliability standard on average under our base modeling assumptions. This convex shape is more consistent

with a gradual decline of reliability at higher reserve margins and helps to reduce price volatility under such market conditions. Similar to the prior recommended change, this revision also would not affect long-term average prices. However, because the recommended convex VRR curve would increase the expected total procured quantity, PJM-wide capacity procurement costs would increase by approximately 0.2%.

The combined effect of these changes is reflected in our recommended convex curve in Figure ES-1. We estimate that adopting these recommendations would result in meeting the 1-in-10 LOLE objective on average, and would reduce the frequency of years below 1-in-5 LOLE to 13% under base modeling assumptions, while also significantly improving VRR curve performance under stress scenarios. The figure also shows NYISO’s capacity market demand curve and ISO-NE’s proposed curve for comparison.



Sources and Notes:

ISO-NE and NYISO curves reported using those markets’ price and quantity definitions in most cases, but relative to PJM’s estimate of 2016/17 Net CONE, Reliability Requirement, and 1-in-5 quantity point for the PJM system.
 Current VRR Curve reflects the system VRR curve in the 2016/2017 PJM Planning Parameters, calculated relative to the full Reliability Requirement without applying the 2.5% holdback for short-term procurements, see PJM (2013a).
 For NYISO Curve the ratio of reference price to Net CONE is equal to 1.185 and is consistent with the 2014 Summer NYCA curve, see NYISO (2014a) and (2014b), Section 5.5.
 ISO-NE Curve shows parameters proposed in April 2014 with cap quantity adjusted to 1-in-5 as estimated for PJM, see Newell (2014b), pp 10-12.

Regarding the local VRR curves that apply to individual LDAs, we find that the current curves result in even greater expected reliability shortfalls than at the system level. Maintaining resource adequacy in LDAs is more challenging because typical fluctuations in supply and demand have a relatively larger impact in small LDAs, and additional uncertainty is introduced by fluctuations in LDA import constraints, as defined by the Capacity Emergency Transfer Limit (CETL) parameters. A single typical change to CETL or the entry or retirement of a single power plant can exceed the width of the entire VRR curve. Consequently, the LDAs are exposed to significantly wider distributions of reserve margin outcomes as a percentage of the local Reliability Requirement. The lower-reliability end of the distributions can bring the average conditional LOLE well below its 1-in-25 target level in many LDAs, particularly in our stress scenarios with higher shocks or with systematic Net CONE estimation error. Moreover, the likelihood of Net CONE estimation error is higher in small LDAs due to idiosyncratic factors (*e.g.*, siting, environmental, or infrastructure related) that may not be incorporated in CONE studies, even if our recommendations related to gross and net CONE are implemented. The small LDAs may offer sparse data on actual projects' costs, and E&AS margins are harder to calibrate if there are few comparable plants.

To improve performance, we recommend that PJM and its stakeholders also apply our system-wide VRR Curve recommendations at the LDA level, and also consider two additional recommended revisions. We estimate that these additional recommendations will result in achieving at least the 1-in-25 conditional LOLE objective on average across all LDAs in a non-stress scenario, while also improving outcomes under the stress scenarios.

- 1. Increase the LDA price cap to 1.7× Net CONE.** We find that a higher cap substantially improves simulated outcomes in LDAs because 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. This would reduce the frequency of price separation from parent zones, but increase the magnitude of those price separation events when they do occur. Similar to all of our other recommendations, long-term average capacity prices would not be affected.
- 2. Impose a minimum curve width equal to 25% of CETL.** We find that raising the LDA price cap to 1.7× Net CONE would not by itself achieve the local reliability objective in a non-stress scenario, with even larger gaps under stress scenarios. Performance is worst in the smallest, most import-dependent zones. To address this performance gap, we find that applying a minimum curve width based on CETL to be a targeted and effective way to improve performance. Under year 2016/17 parameters, applying a minimum width (from point “a” to point “c”) of 25% of CETL would not affect the MAAC or EMAAC VRR curves, but would increase the width in SWMAAC (from 1,351 MW to 1,785 MW), ATSI (from 1,268 to 1,814 MW), PSEG (from 1,004 to 1,560 MW), PepCo (from 703 to 1,433 MW), PSEG-N (from 502 to 683 MW), and ATSI-C (from 481 to 1,273 MW), and DPL-S (from 246 to 459 MW). While this recommendation would not increase long-term average *prices*, it would increase total procurement costs (although by less than 2.3%

depending on the LDA) by increasing the fraction of total capacity procured locally within the LDAs. Moreover, it would likely increase prices in the short term, moving prices in import constrained LDAs from below long-term-equilibrium levels toward equilibrium pricing more quickly.

These results and VRR curve recommendations are based on the assumption that there is no systematic bias in the load forecast, Reliability Requirements, or the Net CONE estimate. However, as noted above, we do find both positive and negative biases in various components of current Net CONE estimates. Hence, our simulation results of VRR curve performance and our associated recommendations assume that these biases will be corrected. We therefore encourage PJM and stakeholders to consider our entire package of recommendations rather than a subset that might bias the results in one direction or the other.

We also note that we took as given the PJM resource adequacy standards that define the “objectives” in our study. Although we discussed resource adequacy standards in our prior RPM reviews, evaluating these standards is not within the defined scope of this present engagement. Other RPM-related topics beyond the scope of this study include: reliability challenges such as winter fuel availability; load forecasting; forward procurement periods and delivery durations; Incremental Auction (IA) design; the 2.5% holdback; participation rules and penalties (*e.g.*, for Demand Response (DR), imports, and new generation); Minimum Offer Price Rules (MOPR) and other mitigation measures.

D. OTHER RECOMMENDATIONS

Through our analyses of the interactions between CONE, E&AS offsets, and VRR curve performance, we also identified some potential improvements to closely-related market design elements that may reduce RPM price volatility or better rationalize prices with locational reliability value. While these following recommendations are not strictly within the defined scope of our study, they are related and would lead to performance improvements that could not be achieved through changes to the VRR curve alone. We therefore offer these additional recommendations for consideration by PJM and its stakeholders:

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 (EUE), 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 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, we see the potential for different types of constraints emerging 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.
3. **Evaluate options for increasing stability of Capacity Emergency Transfer Limits (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 would need to continue to be reflected as changes in CETL, but reducing uncertainty would provide substantial benefits in reducing price volatility. We have provided more detailed suggestions on options to evaluate for mitigating volatility in CETL in our 2011 RPM Review.³
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 added 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 also 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).

³ See Pfeifenberger, *et al.* (2011).

II. Background

This study provides an assessment of the parameters and shape of PJM Interconnection, LLC's Variable Resource Requirement (VRR) curve, used to procure capacity under the Reliability Pricing Model (RPM). As background to this analysis, we provide here a brief overview of the structure of RPM and the VRR curve, along with references to more detailed documentation as available in PJM's Tariff and manuals.⁴

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.⁵ The purpose of this evaluation is to evaluate 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 under all three topic areas, although the full supporting details for our updated CONE estimates are contained in a separate detailed report.⁶

Under the previous 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 August 2011 and June 2008 reports reviewing RPM's performance ("2011 RPM Report" and "2008 RPM Report").⁷ The scope of this study is more narrowly focused than our prior RPM reviews. It does not include a review and summary of RPM auction results, solicitation of stakeholder input, the 2.5% Short-Term Resource Procurement Target (STRPT), the Limited and Sub-Annual Resource Constraints, or an evaluation of other RPM parameters beyond CONE, the E&AS offset, and the VRR curve.

⁴ As the authoritative sources documenting the structure of RPM, see Attachment DD of PJM's Tariff, and Manual 18, PJM (2014 a-b).

⁵ See PJM (2014b, Attachment DD, Sections 5.10.a.iii and 5.10.a.vi.C-D).

⁶ See Newell (2014a).

⁷ See Pfeifenberger (2008, 2011).

B. OVERVIEW OF THE 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 eleventh delivery year of experience, with the next auction scheduled for May 2014 to procure capacity for the 2017/18 delivery year.

RPM is a centralized market for procuring capacity on behalf of all load, with most capacity procured through BRAs conducted three years prior to delivery, and a remaining 2.5% procured through shorter-term IAs. The costs of these capacity procurements are allocated to load serving entities (LSE) throughout the actual delivery year. “Demand” in PJM’s auctions is described by the VRR curve, a segmented downward-sloping 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 diversity 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. All resources are subject to performance requirements and penalties for non-performance during the delivery year.

RPM also allows for self-supply arrangements, whereby entities with load-serving obligations can sell supply into the auction and earn prices that cancel the load’s price exposure on the demand side. RPM also 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 these and other features of the RPM market design in greater detail.⁸ Additional documentation on the parameters and performance of PJM’s RPM include: (a) PJM’s planning period parameters and auction results; (b) our 2008 and 2011 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.⁹

⁸ See PJM (2014 a,b).

⁹ See PJM (2007, 2009a,b,c, 2010, 2011, 2012, 2013a, 2014c), Pfeifenberger (2008, 2011). For PJM State of the Market and periodic reports on RPM, see Monitoring Analytics (2014a-b).

C. DESCRIPTION OF THE VARIABLE RESOURCE REQUIREMENT CURVE

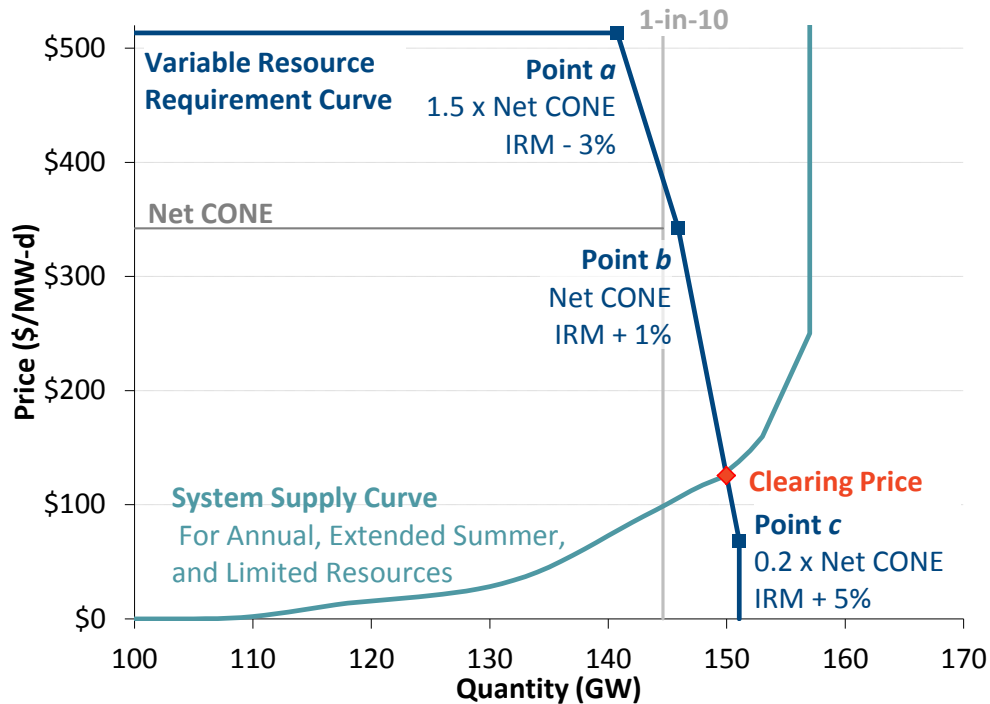
The VRR curve is a downward sloping demand curve illustrated in Figure 1 that is anchored at point “b” at a price of Net CONE and quantity at one percentage point above the installed reserve margin needed to satisfy the system-wide Reliability Requirement. Net CONE is determined as the estimated annualized fixed costs of new entry, or Gross CONE, of a combustion turbine *net* of estimated E&AS margins. The Reliability Requirement is the quantity needed to meet the 1 event in 10 years, or 1-in-10, loss of load event standard.

Gross CONE is estimated administratively as the levelized net revenues that a new entrant needs to earn from the wholesale energy, ancillary, and capacity markets to recover its investment costs. The PJM Tariff stipulates that the parameter be updated through bottom-up engineering cost estimates once every four years, and annual index-based adjustments in other years. The E&AS offset is an administrative estimate of the net revenues that a new entrant with the reference technology would earn from the sale of energy and ancillary services (minus variable costs). Under current RPM rules, the E&AS offset is calculated as a trailing three-year average of estimated historical net energy revenues plus an assumed value for ancillary services revenues (\$/MW-yr) as set forth in the Tariff.¹⁰ Net CONE is then calculated as Gross CONE minus the E&AS offset, and reflects the amount of annual capacity market revenue that the new entrant needs for profitable entry.

The VRR curve is designed to yield auction clearing prices higher than Net CONE when the amount of cleared capacity falls below the target reserve margin, and below Net CONE when cleared capacity exceeds the target. Figure 1 compares the PJM-wide capacity supply curve, VRR curve, and auction clearing price and quantity for the 2014/15 BRA.

¹⁰ See PJM (2014b), Section 5.10.a.v.

Figure 1
Capacity Supply and Demand in RPM
 (Example: 2014/15 Base Residual Auction)



Sources and Notes:

VRR Curve reflects the system VRR curve in the 2014/2015 PJM Planning Parameters. See PJM (2011.)

Supply curve reflects all supply offers for Annual, Extended Summer, and Limited Resources, stacked in order of offer price and smoothed for illustrative purposes.

By definition, the VRR curve yields a capacity price equal to Net CONE at point “b”, at the target reserve margin plus 1 percentage point, or IRM+1%. For lower supply levels to the left of point “b”, capacity prices increase linearly until the quantity drops to IRM - 3% at point “a”, where the capacity price is capped at the greater of: (1) 150% of Net CONE, or (2) 100% of Gross CONE. At higher reserve margins to the right of point “b”, capacity prices decline linearly until IRM + 5% at point “c”, where capacity price is equal to 20% of Net CONE. At even higher reserve margins, the capacity price drops to zero.¹¹

As was noted in the Federal Energy Regulatory Commission order approving the RPM design,¹² compared to a system that simply attempts to procure capacity to satisfy a target reserve margin (*i.e.*, a vertical demand curve), the downward-sloping demand curve is designed to provide the following advantages:

- The downward-sloping VRR curve reduces capacity price volatility by allowing capacity prices to change gradually with changes to supply and demand. The lower

¹¹ Formulas for calculating each VRR curve point are from PJM’s Manual 18, Section 3.4. See PJM (2014a).

¹² December 2006 RPM Order, see FERC (2006), pp. 43-46.

volatility due to a sloped demand curve should render capacity investment less risky, thereby encouraging greater investment at a lower cost.

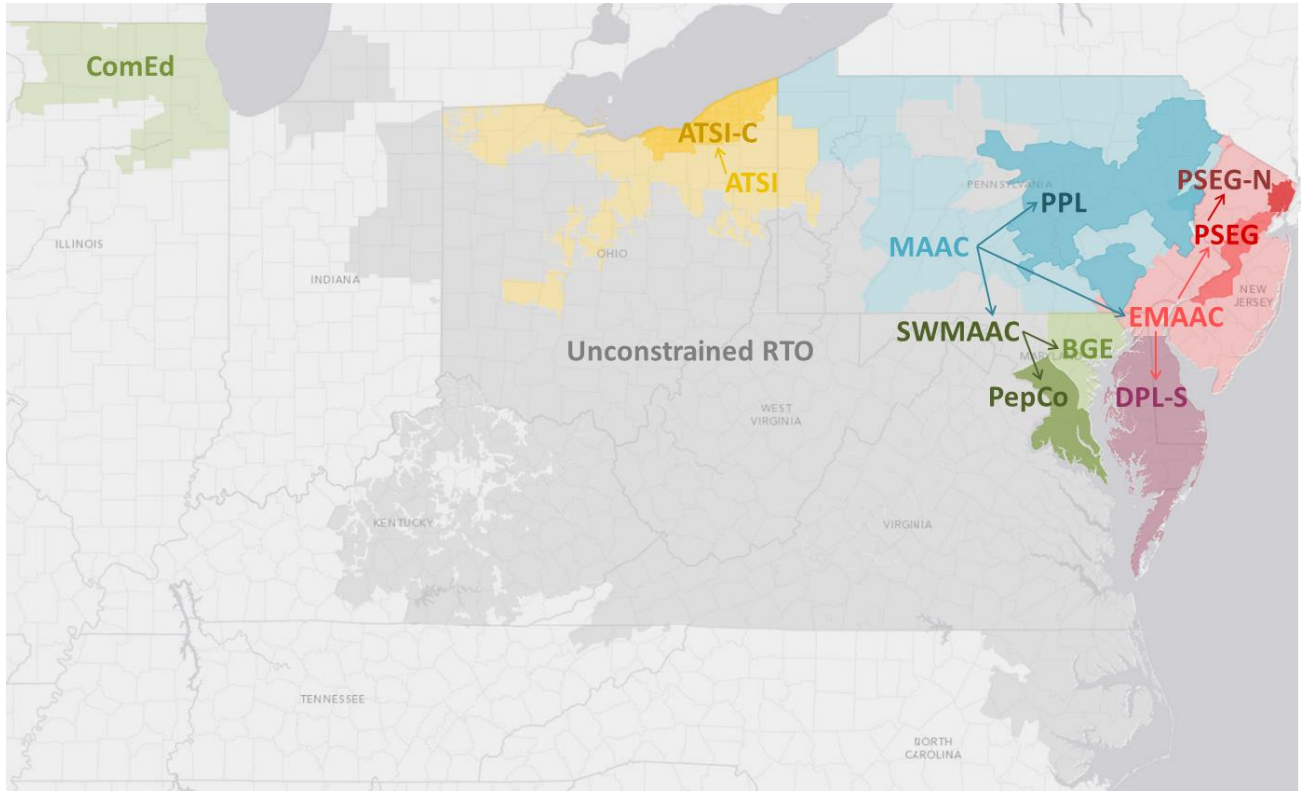
- The sloped demand curve provides a better indication of the incremental and decremental value of capacity at different planning reserve margins. The sloping VRR curve recognizes that incremental capacity above the target reserve margin provides additional reliability benefit, albeit at a declining rate.

The sloped VRR curve also mitigates the potential exercise of market power by reducing the incentive for suppliers to withhold capacity when aggregate supply is near the target reserve margin. Withholding capacity is less profitable under a sloped demand curve close to the target reserve requirements than under a vertical curve because withholding would result in a smaller increase in capacity prices.

At the local level, individual VRR curves are applied to each LDA based on the local Reliability Requirement and locally estimated Net CONE. Modeled LDAs are sub-regions of PJM with limited import capability due to transmission constraints. If an LDA is import-constrained in an RPM auction, locational capacity prices will exceed the capacity price in the unconstrained part of PJM. Currently there are 27 LDAs defined in RPM, although only 12 LDAs are modeled such that capacity auctions could yield different clearing prices as of the 2017/18 delivery year.¹³ Figure 2 is a map of these modeled LDAs, while Figure 3 shows the nested LDA structure as modeled in RPM with sub-LDAs having equal or greater price than all parent-level LDAs.

¹³ Note that there are a total of 13 internal locational prices, considering the 12 LDAs and the unconstrained RTO, plus border prices for each of PJM's defined import prices, and in each internal region there may also be price separation between Annual resources, sub-annual resources, and call-limited resources. For additional detail, see PJM (2014a).

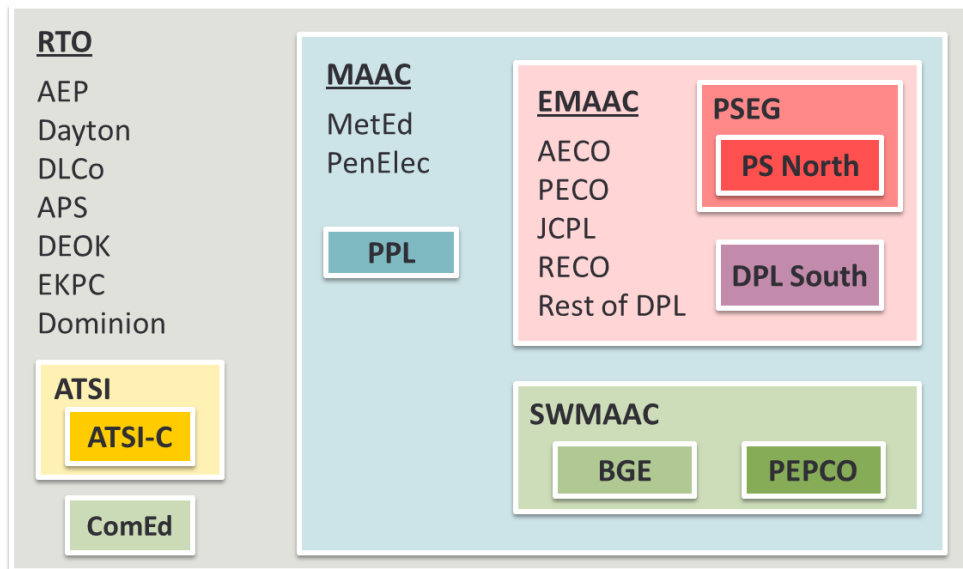
Figure 2
Map of Modeled Locational Deliverability Areas



Sources and Notes:

Map created with SNL Energy (2014); map reflects modeled LDAs as of 2017/18, PJM (2014c).

Figure 3
Schematic of Nested Structure for Modeled Locational Deliverability Areas and Load Zones



Sources and Notes:

Each rectangle and bold label represent an LDA modeled in 2017/18 BRA; individual load zones that are not modeled in RPM auctions are not bold, see PJM (2014c).

III. Net Cost of New Entry Parameter

The prices and quantities of the VRR curve are premised on the assumption that, in a long-term economic equilibrium, new entrants will set average capacity market prices at Net CONE. 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 under continued equilibrium conditions. Thus, in order to achieve the desired reserve margin, the VRR curve is assigned a price equal to Net CONE at approximately the point where the quantity equals the desired average reserve margin.¹⁴ Prices decline as reserve margins increase and rise as reserve margins decrease, but all price points on the curve are indexed to Net CONE.

The VRR curve's performance depends on estimating Net CONE as accurately as possible, and especially not understating it significantly. This is because, the purpose of the VRR curve is to achieve PJM's resource adequacy objectives assuming that the estimated Net CONE value accurately represents the true value that new entrants would need to enter the market. Overstating Net CONE would result in procuring more capacity than needed, causing a modest increase in procurement costs; understating it would result in under-procuring capacity with significantly diminished system reliability. (Long-term average prices would be set by true Net CONE in both cases.) We further examine the magnitude, cost and reliability implications of such over- or under-estimated Net CONE values in Sections V and VI below.

This section of our report analyzes the accuracy and robustness of the administrative Net Cost of New Entry estimate from that perspective. Section III.A addresses Gross CONE, providing updated CONE estimates for the 2018/19 delivery year and recommending a revised cost indexing approach for PJM to apply for the following years' annual updates. Section I.B analyzes the E&AS offset, which PJM subtracts from Gross CONE to produce administrative Net CONE values for each auction. We examine the accuracy of the administratively-determined historical E&AS offset compared to the E&AS margins actually earned by generating units similar to the reference technology. We also recommend that the E&AS methodology be: (1) calibrated to actually-earned E&AS margins of plants similar to the reference technology, and (2) modified to estimate a forward-looking offset. In Section III.C we evaluate possible revisions to the locational definitions of the Gross CONE, E&AS, and Net CONE estimates, and finally, in Section III.D we evaluate options for changing the reference technology, including our recommendation to adopt an average of CC and CT Net CONE estimates.

¹⁴ The exact quantity at Net CONE in the current VRR curve is at IRM + 1%, or slightly higher than the Reliability Requirement, to achieve adequate average performance in spite of likely shocks and uncertainties.

A. GROSS COST OF NEW ENTRY

We provide here a summary of updated engineering cost estimates for PJM's Gross CONE parameters for reference gas CC and gas CT plants, with full supporting detail provided in our concurrently-prepared 2014 CONE Report.¹⁵ These updated CONE estimates would be applicable for adoption in RPM in the 2018/19 delivery year. For the following three years, PJM will update the administrative CONE values using annual index adjustments, currently based on the Handy-Whitman index. We also describe an alternative annual indexing approach that would tie annual updates more closely to underlying cost drivers.

1. Revised Gross CONE Estimates

Updated CONE estimates are needed periodically to ensure that the administrative Net CONE parameter reflects current cost and technology trends. Historically, these estimates have been updated once every three years, and in the future will be updated once every four years.¹⁶ The new CONE estimates, if adopted, would be used as a key parameter defining the VRR curve and as inputs to mitigation thresholds under the MOPR.

As in the 2011 triennial RPM review, we have developed Gross CONE estimates for the current review. We partnered with the engineering services company Sargent & Lundy to provide detailed engineering-based cost estimate that we used to calculate CONE. Table 1 summarizes our recommended CONE estimates for gas CT and CC plants in each of the five PJM CONE Areas for the 2018/19 delivery year. Detailed documentation of these CONE estimates and our study approach is provided in our separate report and associated data files, *2014 Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM* (2014 CONE Report).¹⁷ The installed and annualized cost estimates for these reference CT and CC plants presented in Table 1 are in 2018 dollars. The table also compares our results with the 2011 CONE Study and most recent auction parameters, both adjusted to 2018/19 dollars.

¹⁵ See Newell, *et al.* (2014a).

¹⁶ See PJM (2014b).

¹⁷ See Newell (2014a).

Table 1
Updated CONE Estimates for Gas Simple Cycle and Combined Cycle Plants

		Simple Cycle					Combined Cycle				
		1 EMAAC	2 SWMAAC	3 RTO	4 WMAAC	5 Dominion	1 EMAAC	2 SWMAAC	3 RTO	4 WMAAC	5 Dominion
Gross Costs											
Overnight	(\$m)	\$400	\$373	\$348	\$372	\$364	\$808	\$707	\$709	\$737	\$708
Installed	(\$m)	\$420	\$391	\$364	\$390	\$382	\$885	\$775	\$777	\$808	\$776
First Year FOM	(\$m/yr)	\$6	\$10	\$7	\$5	\$8	\$17	\$30	\$19	\$15	\$19
Net Summer ICAP	(MW)	396	393	385	383	391	668	664	651	649	660
Unitized Costs											
Overnight	(\$/kW)	\$1,012	\$948	\$903	\$971	\$931	\$1,210	\$1,065	\$1,089	\$1,137	\$1,073
Installed	(\$/kW)	\$1,061	\$994	\$947	\$1,018	\$977	\$1,326	\$1,168	\$1,193	\$1,245	\$1,176
Levelized FOM	(\$/MW-yr)	\$15,000	\$25,600	\$18,800	\$13,700	\$19,600	\$26,000	\$44,800	\$29,500	\$23,300	\$28,300
After-Tax WACC	(%)	8.0%	8.0%	8.0%	8.0%	8.1%	8.0%	8.0%	8.0%	8.0%	8.1%
Levelized Gross CONE											
Level-Real	(\$/MW-yr)	\$127,300	\$126,000	\$117,100	\$121,800	\$119,900	\$173,100	\$167,400	\$159,700	\$162,000	\$154,800
Level-Nominal	(\$/MW-yr)	\$150,000	\$148,400	\$138,000	\$143,500	\$141,200	\$203,900	\$197,200	\$188,100	\$190,900	\$182,400
Prior CONE Estimates											
PJM 2017/18 Parameter*	(\$/MW-yr)	\$161,600	\$150,700	\$148,000	\$155,200	\$132,400	\$199,900	\$176,300	\$192,900	\$191,800	\$170,100
Brattle 2015/16 Estimate*	(\$/MW-yr)	\$145,700	\$134,400	\$134,200	\$141,400	\$120,600	\$183,700	\$161,000	\$177,100	\$176,700	\$157,000
Increase (Decrease) Above Prior CONE Estimates											
PJM 2017/18 Parameter	(\$/MW-yr)	(\$11,600)	(\$2,300)	(\$10,000)	(\$11,700)	\$8,800	\$4,100	\$20,900	(\$4,700)	(\$900)	\$12,200
Brattle 2015/16 Estimate	(\$/MW-yr)	\$4,300	\$14,000	\$3,800	\$2,000	\$20,600	\$20,300	\$36,200	\$11,100	\$14,200	\$25,400
PJM 2017/18 Parameter	(%)	-8%	-2%	-7%	-8%	6%	2%	11%	-3%	0%	7%
Brattle 2015/16 Estimate	(%)	3%	9%	3%	1%	15%	10%	18%	6%	7%	14%

Sources and Notes:

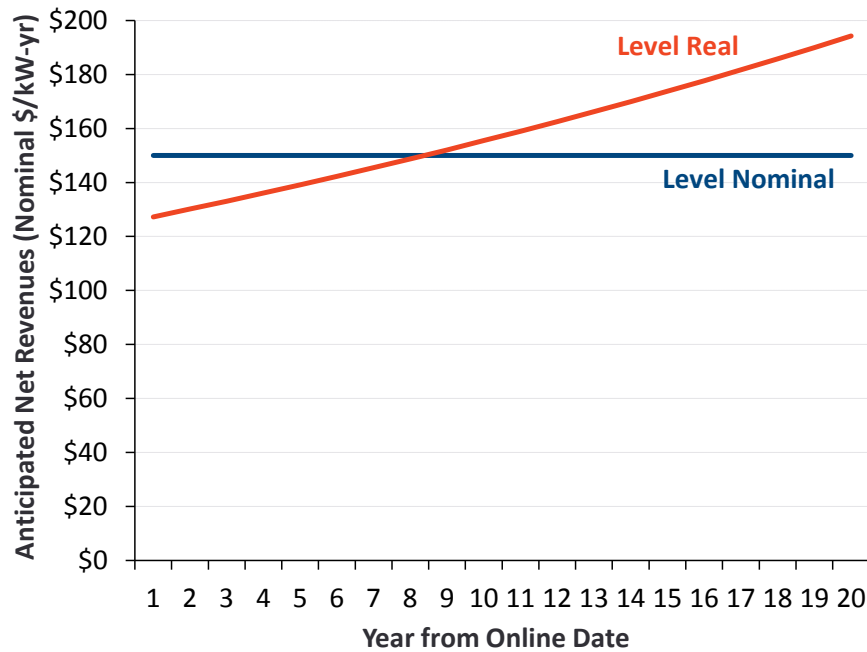
All values are expressed in 2018 dollars, except “overnight” costs, which are in nominal dollars in the year in which they are incurred, see detailed cost estimation in Newell, *et al.* (2014a).

*Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at approximately 3% annually, based on escalation rates for individual cost components.

2. Level-Real vs. Level-Nominal

Table 1 above reports two sets of levelized CONE estimates, one based on “level-nominal” and the other based on “level-real” cost recovery, with a comparison of the two cost recovery trajectories illustrated in Figure 4. Level-nominal cost recovery reflects an assumed 20-year cost recovery trajectory under which the plants’ combined net revenues from the E&AS and capacity markets would remain constant over time in nominal dollar terms, and would not increase over time with factors such as inflation. In contrast, a level-real cost recovery reflects a cost recovery trajectory under which the plants’ operating margin would increase over time at an assumed 2.25% rate of inflation, and so would remain constant in inflation-adjusted real terms. Because the reported CONE value refers to just the *first* year of the assumed cost-recovery trajectory, the level-nominal CONE value is higher with their more pessimistic view of future levels of cost recovery. Under either assumed cost profile, the Net Present Value (NPV) of projected future net E&AS and capacity revenues is the same, such that the investor would recover all capital and fixed costs of the investment, including the cost of capital.

Figure 4
Assumed Cost Recovery Profile under Level-Real and Level-Nominal Levelization
 (EMAAC Combustion Turbine, Online June 1, 2018)



Sources and Notes:

Values reflect anticipated cost recovery profile for EMAAC CT, consistent with our updated CONE estimates from Table 1 and Newell, *et al.* (2014a).

Which approach is more reasonable depends on which trajectory of total net E&AS and capacity revenues is most likely. However, under a well-functioning market that relies on merchant investments, we expect that total future net revenues will be set by the CONE of future entrants. If technology remained unchanged and its costs would be expected to increase with inflation, a level-real cost recovery trajectory (with constant cost recovery in real, inflation-adjusted dollar terms) would be mostly likely.

As we discussed in our 2011 RPM Review, we believe we are not precisely in this world, but one very similar to it.¹⁸ For example, historical costs of combustion turbines have actually risen faster than inflation. If that trend were to continue, CONE values would increase at a rate faster than inflation, which would make near-term cost recovery needs even lower than the level-real CONE value because future cost recovery values would increase faster than the rate of inflation. However, newer turbine technologies have progressively outperformed their older competitors in thermal efficiency. This reduces the older technology’s net revenues at a rate that partially offsets the increase in capacity revenues to the extent that their rate of increase exceeded the rate of inflation. As we have shown in our prior RPM review report, the net effect of these two factors results in a

¹⁸ See Pfeifenberger, *et al.* (2011).

cost recovery trajectory that increases approximately at the rate of inflation, *i.e.*, is approximately level-real.¹⁹

We recognize that this analysis is not fully conclusive about the actual trajectory of cost recovery anticipated by generation developers on a forward-looking basis. One could make a case for attempting to determine projections of future revenues representing actual developers' likely views on energy prices, fuel prices, and capacity prices over the 20-year investment life. The entirety of this information is what ultimately determines the "true" value of CONE. On balance, however, we believe level-real is most reasonable for use in RPM, reflecting an assumption that the trajectory of future operating margins will grow with inflation as the net cost of new plants increases over time. We also note that NYISO and ISO-NE use the level-real approach to estimate CONE for the purpose of setting both their demand curves and MOPR.²⁰

In sum, we conclude that the level-nominal approach currently used by PJM, likely overstates the true value of CONE, which could yield an upward biased VRR curve and could cause RPM to over-procure—assuming administratively-estimated E&AS offsets are not overstated, as they may be. Thus, we recommend that PJM and its stakeholders consider switching to level-real estimates of CONE, but do so in combination with our other recommendations.

3. Annual Updates According to Cost Indices

PJM's tariff specifies that CONE will be updated annually for each year between the periodic CONE studies by applying the Handy-Whitman "Total Other Production Plant" index for the appropriate location.²¹ However, we are concerned that this index has differed significantly from other measures of cost trends for electricity generation plants. Specifically, as shown in Figure 5, this index has escalated more quickly than the rate of cost increases suggested in recent CONE studies.

Aware of this discrepancy, we recently developed an alternative gross capital cost indexing approach for ISO-NE, which it has recently proposed to adopt in its annual Net CONE updating methodology.²² Under this alternative approach, different indices are used for each line item of the cost analysis. These indices are based on the appropriate subsets of the Producer Price Index (PPI) and the Quarterly Census of Employment and Wages (QCEW) datasets published by the Bureau of Labor Statistics. The PPI indices measure the average change over time in the selling prices received by domestic producers for their outputs, and therefore reflect the increase or decrease in construction costs for a different commercial online year. The QCEW indices are developed from a quarterly count of employment and wages reported by employers covering 98% of U.S. jobs, available at the

¹⁹ For a comprehensive discussion of this topic and supporting analysis, see Section IV.A.3 of Pfeifenberger, *et al.* (2011).

²⁰ For example, see Newell, *et al.* (2014c), p. 7 and NERA (2013), p. 55.

²¹ See PJM (2014a), p. 27.

²² See Newell, *et al.* (2014c), pp. 66-67.

county, state, and national levels by industry. We believe this approach is more transparent and more closely tied to the approach we use in our engineering cost estimates than is the Handy-Whitman Index.

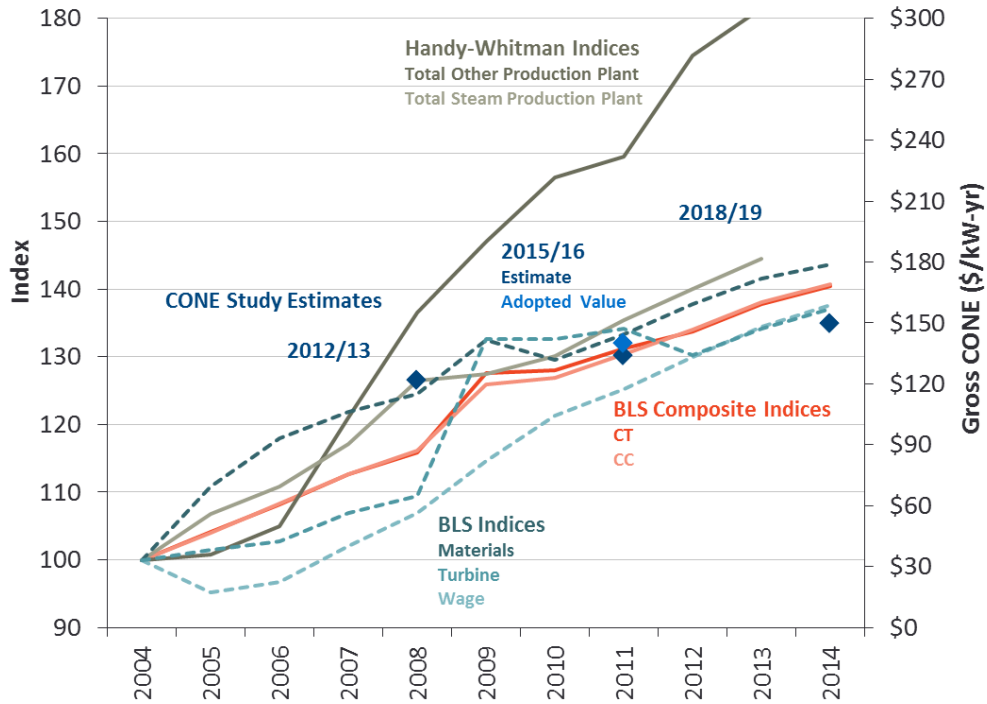
However, the ISO-NE approach is also somewhat more complex, because it involves updating individual cost components and re-levelizing CONE each year.²³ A simpler alternative that could be adopted in PJM would be to update Gross CONE annually using the weighted average of three BLS indices, with the weights of the three indices equal to the relevant proportion of capital costs.²⁴ A resulting composite index is shown in Figure 5, consistent with an appropriate cost index for *CONE Area 1: EMAAC*.

We recommend that PJM and its stakeholders consider adopting this indexing approach. Alternatively, we recommend to at least consider changing from the H-W “Total Other Production Plant” index to the H-W “Total Steam Production Plant” index, which better matches the composite index approach as well as the escalation in successive CONE Studies, as illustrated in Figure 5.

²³ See Newell, *et al.* (2014c), pp. 66-67.

²⁴ The specific indices reflected in the composite index for the example of EMAAC are: (1) BLS Quarterly Census of Employment and Wages: 2371 Utility System Construction: New Jersey – Statewide; (2) BLS Producer Price Index Commodity Data: SOP Stage of Processing: 2200 Materials and Components for Construction; and (3) BLS Producer Price Index Commodity Data: 11 Machinery and Equipment: 97 Turbines and Turbine generator Sets. These indices weighted at 28%, 47%, and 25% for the CT, and 37%, 51% and 12% for the CC, consistent with our estimate of the relevant contribution to plant capital costs in each case, see BLS (2014).

Figure 5
Handy-Whitman Indices Compared to Weighted-Average of BLS Indices



Sources and Notes:

BLS indices retrieved in April 2014 from BLS (2014).
 The composite BLS indices were calculated using the costs of labor, material and turbine as approximate percentages of total project costs, developed in Newell, *et al.* (2014a).
 Handy-Whitman indices refer to the North Atlantic Region. See Whitman (2014).

B. NET ENERGY AND ANCILLARY SERVICES REVENUE OFFSET

PJM determines administrative Net CONE values for each CONE Area just before each three-year forward auction. The Gross CONE value is based on CONE studies previously conducted once every three years and to be conducted once every four years in the future, with escalation applied annually for years between these periodic studies. Net CONE is calculated as Gross CONE minus E&AS margins, which PJM calculates annually by conducting a virtual dispatch analysis of the reference resource against electricity and gas prices over the prior three years.

In this section, we analyze how accurately PJM’s E&AS calculations reflect the value developers can reasonably expect to earn. We focus on: (1) the accuracy of PJM’s historical analysis; and (2) the applicability of the historical data to the future delivery period. We find that the historical analysis appears to accurately represent actual units’ E&AS margins for CTs in most locations, but overstates CT margins in SWMAAC and substantially overstates CC margins in all locations. Regarding applicability, we explain how the historical data may not represent future E&AS margins due to anomalous historical events as well as evolving market conditions and rules. The result may result in bias or volatility PJM’s Net CONE estimates, potentially threatening RPM performance. Hence, we

present recommendations for avoiding such errors and developing a more accurate forward-looking E&AS estimation approach.

1. Accuracy of Historical Simulation Estimates

To assess the accuracy of PJM's historical simulation estimates of the reference resources' E&AS margins, we compare these historical estimates to the actual E&AS margins of similar existing units earned over the same period. Historical simulation estimates were provided by PJM staff for each PJM energy zone in each historical year.²⁵ Actual unit-specific E&AS margins were provided by the Independent Market Monitor, reflecting the IMM's estimate of total energy, ancillary, and make-whole revenues minus fuel, variable operations and maintenance, and other costs. To ensure a relevant comparison, we compare actual E&AS margins only for units that we identify to be similar to each of the reference resources, based on fuel type, unit type, online date, and unit size.

While we conducted this comparison on a zone-specific, yearly basis, we report a more aggregated summary comparison by CONE Area in Figure 6 to protect confidential data. The chart shows average actual E&AS margins on the x-axis, and the E&AS simulation error (actual minus simulated E&AS) on the y-axis. We also qualify the conclusions we report here by explaining that: (a) a comprehensive detailed comparison is not possible in some zones without existing units similar to the reference units; (b) we observe a wide range of actual E&AS margins, some of which we attribute to poor data quality or uniquely-situated units that we exclude from our sample; and (c) our analysis here covers only annual net E&AS data. More detailed monthly data on revenues, output, and costs would likely provide a more comprehensive basis from which to conduct a more thorough comparison or calibration exercise.

These charts, along with our more detailed zonal comparison of PJM's estimates to actual E&AS margins, suggest that the E&AS estimate for CTs is accurate on average over multiple years in most locations. However, PJM's E&AS estimate for CTs appears to be substantially overstated for SWMAAC (although data for that location are not displayed in the chart). For the CC, we find that PJM's simulated E&AS estimate is systematically over-stated by approximately \$40,000/MW-yr on average across locations and years.

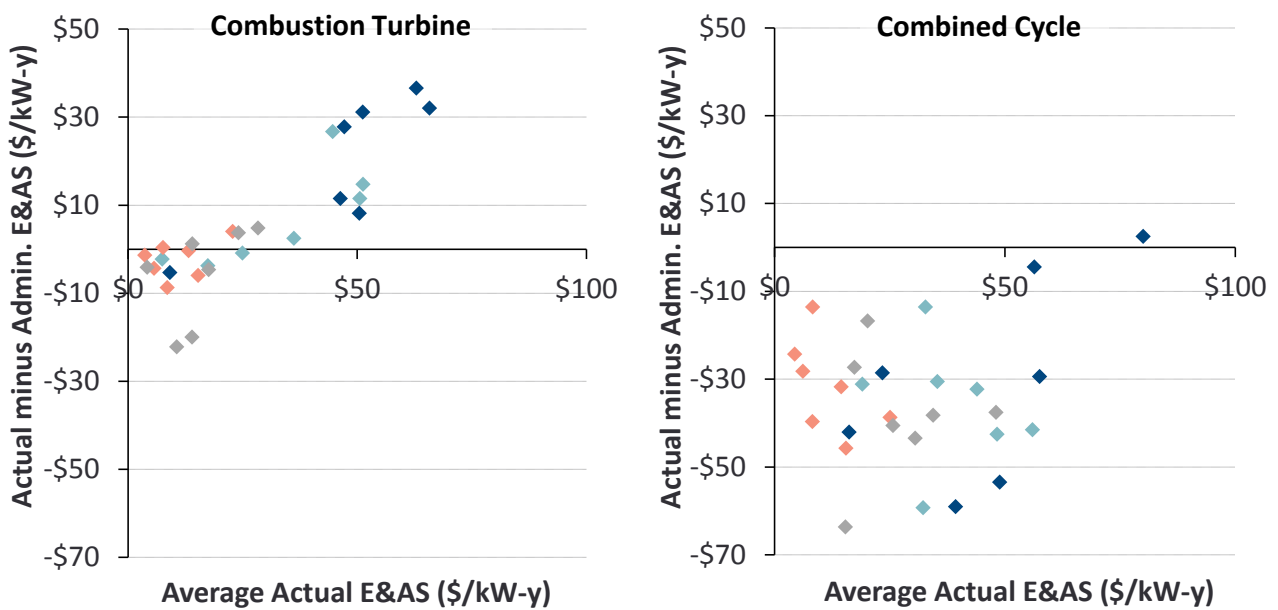
In SWMAAC, this comparison is a particular challenge because there are no installed CT or CC units similar to the reference unit, and so we report a comparison with older and smaller CTs and no comparison for CCs. While acknowledging these comparisons are challenging, we believe that the data show that PJM's simulation estimates systematically exceeded actuals in that location, and by more than in other regions of PJM (although possibly by a bit less than the \$25,000/MW-yr found by our calculations, given the comparison against older and smaller units). This discrepancy appears to be attributable to unavailability of non-firm natural gas or inflexible gas scheduling capabilities in

²⁵ A subset of these same historical estimates are used to calculate PJM's historical E&AS in the BRA planning parameters.

the SWMAAC region, causing actual units to generate rarely and to more often rely on expensive oil when they do run. The current historical simulation calculations do not account for the higher costs associated with these challenges, causing an overestimation of the E&AS offset and, consequently, an underestimated Net CONE value.

To avoid these inaccuracies and biases, we recommend that PJM more comprehensively analyze the source of overstated E&AS estimates and then calibrating simulated E&AS margins against actual plants' operational or net revenue data (including gas deliverability issues) for CCs in all locations, and for CTs in SWMAAC specifically. This analysis and calibration could involve an analysis of an expanded set of monthly output, fuel consumption, cost, and revenue data for actual plants, using the expanded dataset to provide more insight into potential causes of any discrepancies. For locations in which no units similar to the reference CC or CT are available, PJM may need to validate its method compared to units dissimilar to the reference unit or based on similar units in nearby locations.

Figure 6
Actual Minus Simulated E&AS Margins over 2007-2013



Sources and Notes:

SWMAAC data not shown due to lack of CCs similar to the reference unit and CTs dissimilar from the reference unit.
 Reflects CTs > 140 MW and online since 2000; reflects CCs > 500 MW, online since 2000, not cogen.

2. Backward- versus Forward-Looking E&AS Offset

PJM uses a three-year historical average of simulated values to estimate E&AS margins, as required by the Tariff since the inception of RPM.²⁶ The primary advantage of this historical approach is its relative simplicity and transparency in comparison to the greater complexity of forecast-based

²⁶ See PJM (2014b), Section 5.10.a.v.

approaches. Moreover, it should provide an unbiased estimate that should result in an accurate Net CONE on a long-term average basis, even if the values are not accurate in any particular year.

However, as we explained in our past RPM reviews, this historical E&AS approach based on the last three years of spot market prices for energy and ancillary services is quite volatile. The current historical approach may yield E&AS margins that reflect neither normal nor expected future market conditions. For example, a single year with a substantial number of shortage pricing events or major changes in fuel prices can substantially distort Net CONE from reasonable forward-looking estimate, which increases the volatility of capacity prices.

The fact that these administrative estimates can differ substantially from market expectations at any particular time also creates RPM performance concerns. For example, three years of historical data can be highly affected by anomalous market conditions that are not likely to be repeated. Resulting distortions may become especially pronounced under PJM's new shortage pricing mechanisms, which allow extreme weather or fuel market conditions to produce very high E&AS margins. With a four- to six-year delay between the historical years and the delivery year, the historical average may not be representative of evolving market conditions. This could result in significantly underestimated Net CONE values (and an under-procurement of capacity) for the three delivery years that are affected by the anomalous high-price historical year.

To address these concerns, we recommend that PJM consider developing and adopting a forward-looking E&AS estimation approach. We recognize that developing a fundamentals-based estimate would be difficult to conduct with enough simplicity, transparency, and objectivity to gain widespread stakeholder support. Instead, we recommend developing an estimate of E&AS margins based on publicly-available futures prices, an approach that ISO-NE has recently adopted with full stakeholder support.²⁷ Futures prices will average out extreme weather years and also reflect market participants' expected changes in fundamentals.

We illustrate this concept in Figure 7, showing the average of EMAAC zonal values for: (a) PJM's historical E&AS simulation estimates (blue for CC, red for CT); and (b) a three-year average of PJM's historical estimate, after a three-year delay consistent with the relevant RPM delivery year (blue dotted for CC, red dotted for CT). We then compare these values against a simplified illustrative back-cast and forecast of E&AS margins using monthly data for fuel prices, on-peak power, and off-peak power.²⁸ We conduct a simplified CC and CT dispatch on a monthly basis using the reference

²⁷ See Newell, *et al.* (2014c), Section VIII.

²⁸ The monthly prices reflected in this analysis are: (a) historical gas prices at Transco Zone 6 Non-New York; (b) futures gas prices at Henry Hub, plus a basis swap to Transco Zone 6 Non-New York, assuming that the basis differential increases with inflation in years beyond the horizon of data availability; (c) historical on-peak and off-peak electric prices based on day-ahead monthly average prices, calculated as the average price across all energy zones within EMAAC; and (d) energy futures prices based on the forward curve at PJM West Hub, with the basis differential between PJM West Hub and the EMAAC

unit's heat rate and typically operating costs that increases with inflation.²⁹ We attempted to match historical simulation values (not actuals) in this illustrative calculation.

Based in this illustrative calculation, current forward curves indicate \$20,000/MW-yr lower E&AS margins for CCs compared to the historical 3-yr estimate in EMAAC. This discrepancy between the margins means that PJM's administrative Net CONE estimate for year 2017/18 may be overstated compared to the revenues anticipated by a typical new CC developer. This would not translate into a reliability concern if CC CONE is only used for MOPR purposes, but would be a bigger concern if CC Net CONE were also used in the VRR curve.

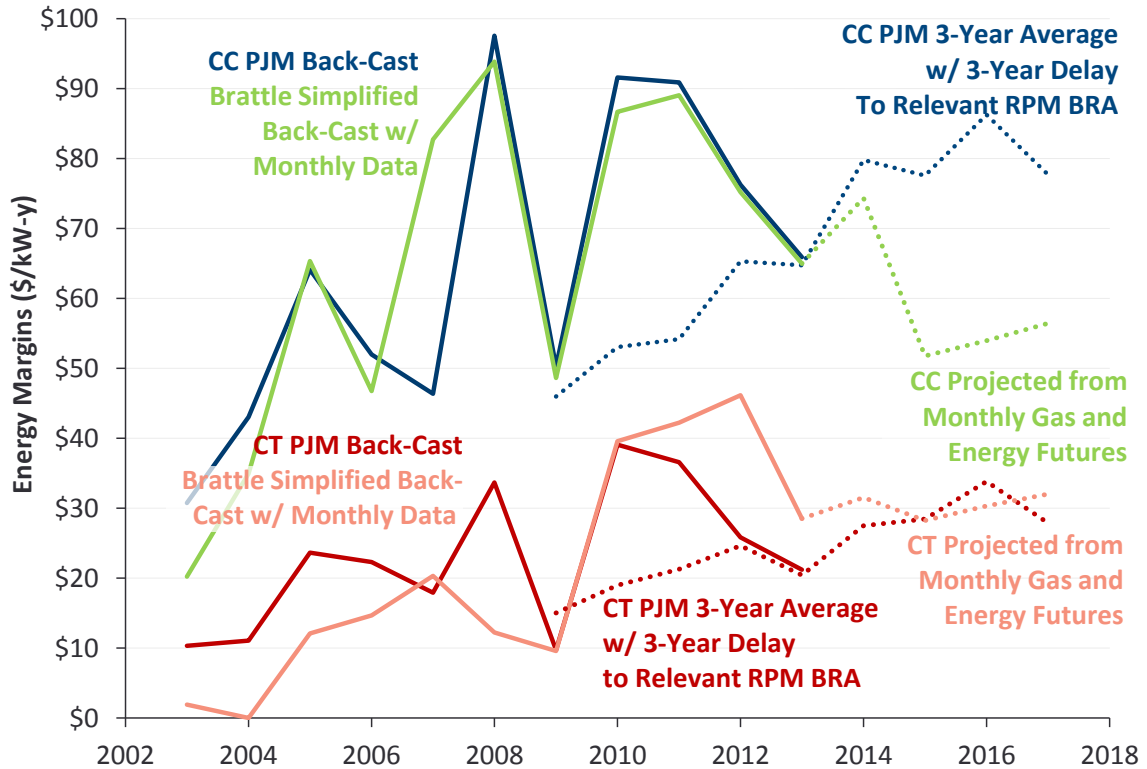
For CTs, which is the reference technology currently used as the basis for Net CONE in the VRR curve, estimated E&AS revenues are similar in EMAAC for the illustrative backward and forward-looking approaches. However, we note that we would not expect such consistency to persist through changing market conditions. Rather, we anticipate periodic discrepancies similar to what we currently observe for CC plants. We also note that a futures-based E&AS approach is likely to be more accurate for a CC than for a CT, because the 5x16 on-peak hour period associated with on-peak futures approximately coincides with the dispatch period of a CC. In contrast, E&AS margins for CT plants are determined by a much smaller number of super-peak hours.

Continued from previous page

average calculated as the average of the Rounds 1, 2, and 3 2014/17 Long-Term FTR Auction implied congestion differentials for the 2014 through 2017 delivery years (adjusted to a monthly series based on the difference between the average annual differential and average differential in each month over the last five historic years), plus the 3-year average of losses differentials, with both losses and congestion costs assumed to increase with inflation for years beyond data availability. See PJM (2014b, 2014c, and 2014d.), Bloomberg (2014), Ventyx (2014), and SNL (2014).

²⁹ This simplified calculation reflects the net E&AS revenues of a unit that turns off or on for all on-peak hours of the month (and separately turns off or on for all off-peak hours), if the unit has no start costs, no changes to heatrate over the year, no dispatch constraints, no ancillary revenues, and is always available. These illustrative calculations assume CC and CT heatrates of 10,094 Btu/kWh and 6,722 Btu/kWh respectively, as calculated in our prior CONE study, see Spees, *et al.* (2011). We adjust the assumed VOM for both the CC and CT until the resulting E&AS back-cast approximately match PJM's historical simulations, resulting in \$6/MWh and \$0/MWh for the CC and CT respectively in 2013\$.

Figure 7
Comparison of Historical and Forward-Looking E&AS Estimates



Sources and Notes:

Simplified historical and futures calculation use monthly data for gas and electric prices to calculate net revenues for a plant dispatched across an entire month of on- or off-peak hours. Gas prices are at Transco Z6 NNY, electric prices are zonal based on energy futures at West Hub plus a basis differential. The basis differential is derived from annual long-term FTR auctions (with a monthly shape adjustment consistent with historical energy price differentials), plus a losses factor proportional to the West Hub energy price.

As with historical recommendations above, it would be important to carefully calibrate this forward-looking approach against historical actuals to the extent that they are available in each location. Monthly calibration data would likely provide a sufficiently comprehensive data set from which to test the accuracy of the historical calculation under range of realized gas and electric price conditions. It may be possible to match historical actual data using small adjustments to this simplified approach, or it may be necessary to consider additional refinements, *e.g.*, to incorporate extrinsic value, or unit commitment inefficiencies.

C. LOCATIONAL NET CONE APPROACH

PJM is a large multi-state region covering a large number of energy zones with sometimes substantially different energy prices and with very different going-forward costs for investing in new generation. As such, Net CONE may be quite different across the footprint, introducing a challenge for estimating an appropriate administrative Net CONE in each location. In this section, we review PJM’s approach for selecting the appropriate locations for which to estimate Gross CONE, the E&AS

offset, and finally Net CONE, and then how these parameters are assigned to each LDA for the purposes of calculating the local VRR curve.

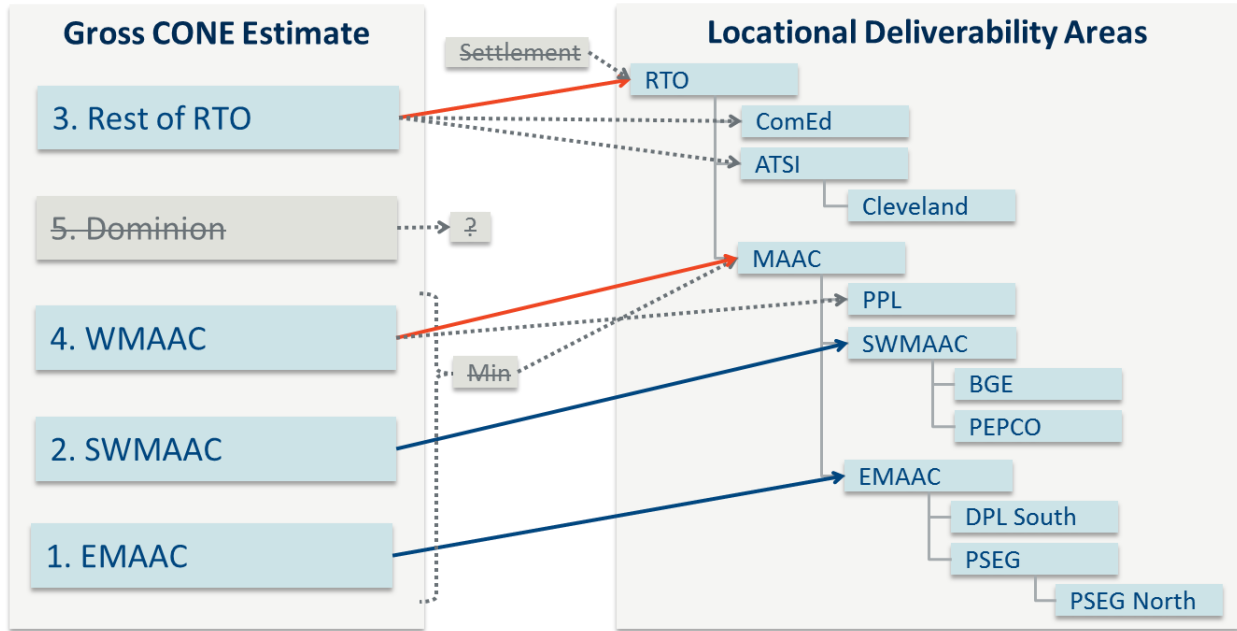
In general, we follow a guideline that the Gross CONE and E&AS parameters should be broadly representative of the economics within each modeled LDA, with the parameters matched as closely as possible to the boundaries of the particular LDA. We also recognize in this review that there are some realistic bounds to the level of accuracy possible in estimating Net CONE, given the range of unique circumstances faced by developers and some unavoidable level of error in these administrative estimates.

1. Mapping of Locational Gross CONE Estimates

Currently, PJM's Tariff specifies five different CONE Areas for which administrative Gross CONE estimates must be developed once every three years historically, and once every four years going forward; it also specifies a sixth CONE value to be used in the system-wide VRR curve.³⁰ The CONE estimates are then mapped into individual LDAs for the purposes of calculating the locational Net CONE estimates and locational VRR curves. In reviewing these locational considerations, we identified a series of potential revisions that may be made to: (a) better align the geographic definitions of the Gross CONE estimates and the LDAs that those estimates are assigned to; (b) reduce the number of administrative CONE estimates to reduce administrative complexity, while maintaining distinct CONE estimates where needed; and (c) recognize the possibility that additional CONE estimates might be needed in the future. We summarize these possible revisions in Figure 8 and Table 2.

³⁰ See PJM (2014b), Section 5.10.a.iv.

Figure 8
Potential Revisions to Gross CONE Mapping



Sources and Notes:

Current mapping from PJM’s Tariff and 2017/18 Planning Parameters, see PJM (2014b-c).

Blue and gray dotted lines reflect current mapping of CONE estimates to LDAs; crossouts represent existing elements that we recommend eliminating; red lines represent our recommended revised mapping.

To better align CONE Areas to individual LDAs, we make two recommendations. First, we recommend adopting the *CONE Area 3: Rest of RTO* estimate for the system-wide VRR curve, rather than continuing to use the fixed tariff value that was adopted as part of a settlement process after the most recent CONE study.³¹ This change would allow the system curve to adjust with periodic CONE study estimates, as with other locations in the system. Second, we recommend adopting the *CONE Area 4: Western MAAC* estimate for the MAAC VRR curve rather than adopting the minimum of sub-LDA Net CONE values.³² This revised mapping would: (a) be more consistent with the expected result that the most import-constrained sub-LDAs of MAAC should have higher Gross CONE estimates (although we acknowledge that this has not always been the case historically, it is true in the present CONE estimates and we anticipate that it will continue to be true in the future); (b) result in a more stable and accurate Net CONE estimate for MAAC; and (c) avoid incorporating downward bias into the MAAC Net CONE estimate, which can be introduced by taking the minimum of three estimates (for Western MAAC, Eastern MAAC, and Southwest MAAC) each of which has some administrative error.

³¹ See PJM (2014b), Section 5.10.a.iv

³² We also note that the Tariff wording is relatively unclear and may leave ambiguity regarding whether it refers to the minimum of sub-LDA Gross CONE or Net CONE values. Note that this provision does not apply to any LDA other than MAAC, and has consistently resulted in SWMAAC Net CONE values being used for MAAC. See PJM (2014b).

To reduce the number of CONE estimates, we identify only one recommended change: to eliminate *CONE Area 5: Dominion* and combine it with *CONE Area 3: Rest of RTO*. We recommend this change because Dominion has never been a modeled LDA and so that location's CONE estimate has never been used for determining a locational VRR curve. Eliminating this CONE estimate will somewhat reduce administrative complexity and cost. The remaining four CONE estimates would remain as applicable for the four permanent LDAs that PJM has determined will always be modeled in RPM: Eastern MAAC, Southwest MAAC, MAAC, and Rest of RTO.

It is also possible that the number of CONE estimates could be further reduced, given that in many cases the locational CONE estimates have not resulted in large variations by region beyond the range of administrative error. While we find this option appealing, we recommend against it primarily because it would still be necessary to evaluate in the periodic CONE studies whether the locational differentials are likely large enough that separate CONE estimates would be needed in the future. Such a determination is hard to make without following through with a full locational CONE estimate or gathering a sufficient number of locational cost indicators, reintroducing some complexity and cost. Ultimately, the change may not result in substantial improvement unless two CONE Areas can be shown to be consistently similar such that they can be permanently combined, which does not appear to be true at the present time.

Finally, we recommend that PJM introduce a test or test(s) to identify cases where additional CONE estimates may be needed in the future. The particular case of concern could materialize if there is an import-constrained sub-LDA that is smaller than any of the CONE Areas that has a structurally and permanently higher Gross CONE and Net CONE than in surrounding areas, and within which it may not be possible to sustain resource adequacy.

Table 2
Summary of Possible Revisions to Locational Gross CONE Approach

Potential Change	Rationale
Use RTO CONE Estimate for RTO VRR Curve <i>(Rather than Fixed Settlement Number)</i>	<ul style="list-style-type: none"> • Legacy of most recent settlement agreement that currently the RTO Gross CONE number is not based on the periodic CONE study estimates, but rather set at a fixed value agreed in settlement (updated with Handy-Whitman) • Revert to a standard approach consistent with other Areas' Gross CONE updates
USE WMAAC CONE for MAAC VRR Curve <i>(Rather than Minimum of Sub-Areas)</i>	<ul style="list-style-type: none"> • Currently, Tariff states that LDAs spanning multiple CONE Areas will use the minimum CONE of sub-LDAs, historically always SWMAAC • Revised approach is more consistent with underlying theory that the most import-constrained areas should have the highest Gross CONE and Net CONE
Eliminate CONE Area 5: Dominion	<ul style="list-style-type: none"> • Dominion CONE estimate is not used in setting VRR curves as Dominion has never been a modeled LDA
Add Test to Trigger a Separate Gross CONE Estimate for Small LDAs	<ul style="list-style-type: none"> • Current approach always estimates Gross CONE for the permanent, large LDAs (RTO, MAAC, SWMAAC, & EMAAC) • But in some LDAs, it is possible there could be a circumstance where the reference technology would not be feasible to build, or would be far more expensive to build in some difficult sub-areas. If Net CONE in that sub-zone is close to 1.5× Net CONE of the parent, then RPM would not be able to achieve resource adequacy in that subzone • The test might consider whether the LDA is persistently import-constrained, shows little evidence of new entry, and shows evidence of structurally higher entry costs (<i>e.g.</i>, if the reference technology cannot be built there)

2. Mapping of Energy and Ancillary Services Offsets

Currently, PJM estimates E&AS offsets for each CONE estimate based on the specified location of the original reference unit at the time that the tariff language was written.³³ These E&AS offsets are used to develop seven different Net CONE estimates used in the VRR curves in different locations in PJM: (a) one for use the system-wide VRR curve, based on the RTO-wide average LMP; (b) one for each of the five CONE Areas, and the resulting Net CONE values are applied to all LDAs within each CONE Area; and (c) the MAAC Net CONE, which is equal to the lowest Net CONE value of the three CONE Areas within MAAC, which are WMAAC, EMAAC, and SWMAAC.³⁴

³³ Note that subsequent CONE studies have specified different reference unit locations but these revised locations were not incorporated into the tariff. See PJM (2014b), Section 5.10.a.iv and PJM (2013a.)

³⁴ Note that these mappings are slightly different from the mappings used for MOPR, which include only five values consistent with the five CONE Areas, see PJM (2014d).

The result of this mapping process is that the E&AS offset incorporated into individual LDAs' Net CONE and VRR curve is usually developed based on energy prices from a different location, as summarized in Table 3 for the 2017/18 delivery year. In fact, only the RTO-wide, Commonwealth Edison (ComEd), and Baltimore Gas and Electric Company (BGE) Net CONE values are based on E&AS offset values estimated specifically for that location. The other ten modeled LDAs are not mapped as closely as possible, meaning that there is potential for systematic discrepancies between the administratively-estimated and true developer Net CONE in these areas.

Table 3
Summary of Possible Revisions to Locational Gross CONE Approach

LDA	E&AS Zone	Relationship
RTO	PJM Average	Self
ComEd	ComEd	Self
ATSI	ComEd	Peer
Cleveland	ComEd	Parent's Peer
MAAC	BGE	Sub-Sub-LDA
PPL	MetEd	Peer
SWMAAC	BGE	Sub-LDA
BGE	BGE	Self
PepCo	BGE	Peer
EMAAC	AECO	Sub-Zone
DPL South	AECO	Peer
PSEG	AECO	Peer
PSEG North	AECO	Parent's Peer

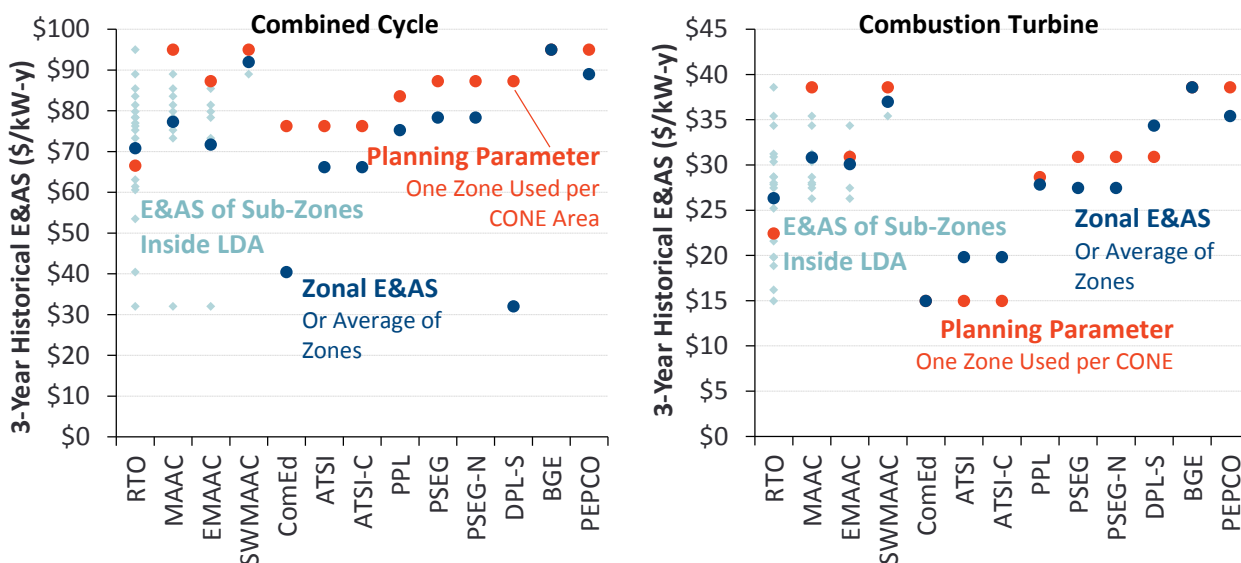
Sources:

Current mapping from PJM's Tariff and 2017/18 Planning Parameters. See PJM (2014b-c).

To address this potential mismatch, we recommend that PJM expand the number of Net CONE estimates and calculate a separate number for each of the modeled LDAs. In each case, the E&AS offset would be calculated using energy prices that match as closely as possible the energy prices applicable in each LDA. Figure 9 illustrates the impact of remapping E&AS parameters in this way using the 2017/18 Planning Parameters, and PJM's administrative E&AS estimate based on zonal

average energy prices in each location.³⁵ This remapping on the reference CT would result in a lower E&AS (higher Net CONE) in seven of the thirteen LDAs according to 2017/18 parameters, with the CT E&AS dropping by \$1,000-\$8,000/MW-yr ICAP in most LDAs, but increasing by \$3,000-\$5,000/MW-yr ICAP in the areas where it goes up. The CC E&AS parameters as used for MOPR would follow similar patterns, although the mapping used for MOPR is somewhat different.³⁶

Figure 9
Three-Year Average E&AS Offset from 2017/18 Parameters vs. if Remapped to the Closest LDA



Sources and Notes:

All E&AS offset estimates reflect historical three-year averages of PJM estimates over calendar years 2011-13, as expressed on a \$/kW-yr ICAP basis, and including the tariff-defined fixed A/S adder.
 For RTO, "Planning Parameter E&AS" based on Average Zonal LMP, "Zonal E&AS" based on average E&AS of zones.
 Historical E&AS offsets as used from 2017/18 Planning Parameters, see PJM (2014c.)
 Other zones' estimated historical E&AS offset supplied by PJM staff.

3. Option to Impose a Minimum Net CONE at the Parent LDA Level

One concern that we observe is that in some cases the locational Net CONE estimates result in small LDAs having administrative Net CONE below the parent LDA's Net CONE. This is particularly true in Southwest MAAC, which has historically had high energy prices and E&AS offset resulting in a Net CONE estimate substantially below the other LDAs. This low Net CONE in Southwest MAAC has then also propagated up to MAAC based on the minimum Net CONE rule that we recommend eliminating as explained above.

³⁵ For LDAs that cover multiple zones we use a simple average of E&AS estimates, and for sub-zonal LDAs we use the E&AS offset as estimated for the entire zone. Additional accuracy could be achieved by estimating E&AS offsets based on the injection-weighted average LMP across all generation buses contained within a particular LDA.

³⁶ The MOPR estimates include only five values consistent with the five CONE Areas, see PJM (2014d).

First, we note that it is not necessarily a concern for administrative Net CONE to be lower in sub-LDAs, as long as the administrative Net CONE is accurate and equal to the true developer Net CONE. In this case we would expect developers to identify this low cost (or high energy revenue) location as an attractive opportunity for building. In fact, whenever the parent LDA is in need of capacity, suppliers would choose to site in the sub-LDA, with the likely result that the sub-LDA would never price separate according to its own VRR curve and maintain more than sufficient capacity to meet its Reliability Requirement. The local VRR curve would then be a non-binding constraint, and the sub-LDA would eventually cease to be a modeled LDA unless it were one of the four permanent LDAs.

In fact, the attractiveness of investing in locations with the lowest Net CONE is the reason that we would not expect Net CONE to be lower for any extended period of time. In general, would expect load pockets to be persistently import-constrained from a resource adequacy perspective only if there are structurally higher going-forward costs associated with developing assets in that location. For example, a load pocket may be persistently import-constrained if there are substantial siting difficulties, environmental restrictions, or lack of available infrastructure that make it more costly to build. Lower energy revenues may also be a driver of higher Net CONE in sub-regions, for example if gas availability substantially restricts dispatch and reduces potential energy margins.

In cases where administrative Net CONE deviates from this expectation (showing lower Net CONE in persistently import-constrained sub-regions), it may be caused by errors in the administrative estimate. We believe this to be the case in Southwest MAAC, where high local energy prices have driven administrative Net CONE substantially below other areas (with the results propagating up to the larger MAAC LDA). However, despite the apparently more attractive investment opportunity, we observe relatively less investment activity in that location compared to the much greater levels of investment in other locations including other locations with lower capacity prices.³⁷

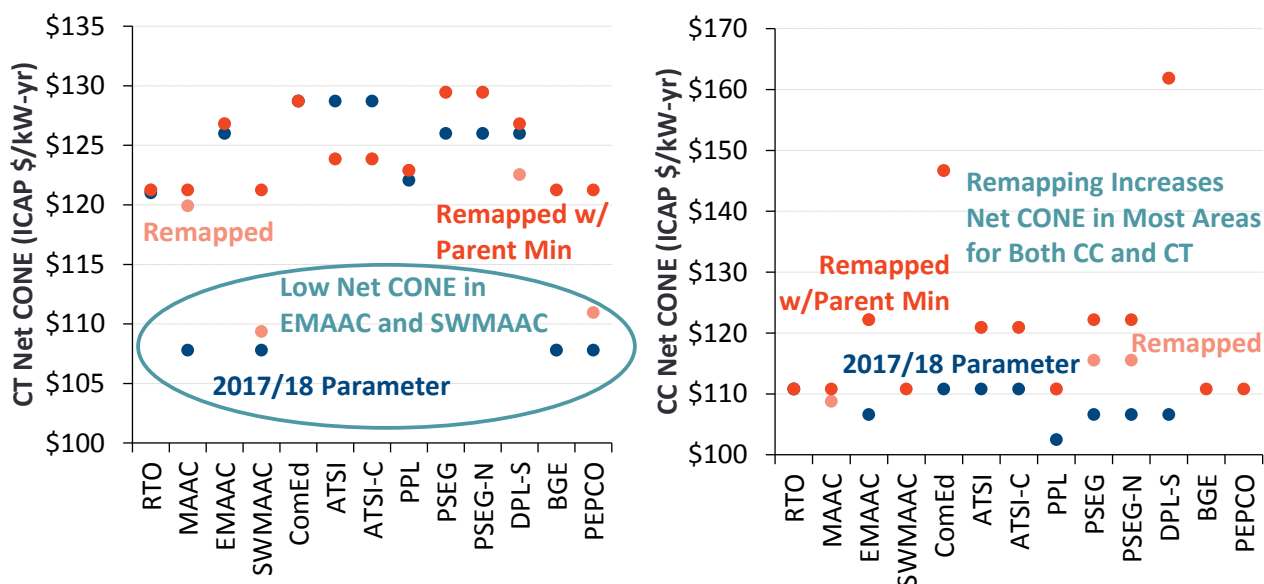
Some of this disconnect may be resolved by a close calibration of E&AS estimate to actual plants' net revenues as discussed in Section III.B.1, it may be further addressed by making note of potential siting and investment cost concerns as we discuss in our CONE study.³⁸ However, the potential to refine these estimates consistent with true costs and revenues, will be limited in locations where there are no plant similar to the reference resource and limited development activity. The limited ability to more accurately capture locational costs is also more difficult in small LDAs, for which there is no location-specific CONE estimate. These locations are the most at risk for under-estimated Net CONE, since there may be localized siting, permitting, or infrastructure concerns that prevent the reference resource from being built even if there are no such concerns in the broader CONE Area.

³⁷ Based on analysis of new plants cleared in RPM and under construction in SWMAAC compared to other regions of PJM, using data obtained from Ventyx (2014) and news reports from SNL Energy (2014).

³⁸ See Newell, *et al.* (2014a).

For these reasons, we recommend that PJM consider imposing a minimum on LDAs' Net CONE that would prevent import-constrained sub-LDAs from having Net CONE below the parent LDA value. We would recommend applying this rule to all LDAs, but particularly for the smallest, non-permanent LDAs for which there is no CONE estimate. Figure 10 shows the combined impact of imposing this minimum and remapping Net CONE as discussed in prior sections, using PJM's 2017/18 Planning Parameters. As the charts show, remapping would cause Net CONE to increase in most locations for both the CC and CT. The parent minimum would be binding in four locations for the CT and one location for the CC, with the most substantial effect being to increase Net CONE in SWMAAC and its sub-LDA PepCo.

Figure 10
Impact of Remapping Gross and Net CONE using 2017/18 Parameters
 With and Without Imposing a Parent Minimum on LDA Net CONE



Sources and Notes:

Gross CONE, E&AS, and A/S values consistent with PJM 2017/18 Planning Period parameters, see PJM (2014c).

Other E&AS values reflect historical three-year averages of PJM estimates over calendar years 2011-13, as expressed on a \$/kW-yr ICAP basis, and including the tariff-defined fixed A/S adder.

D. REFERENCE TECHNOLOGY AS COMBINED CYCLE OR COMBUSTION TURBINE

As noted earlier, PJM has been utilizing a frame-type combustion turbine plant as its reference technology for the purpose of defining Net CONE for the VRR curve. However, as summarized in our concurrently-published CONE study, very few such plants have recently been built or are being built in PJM today.³⁹ This is particularly true for merchant generators, who have been developing primarily combined cycle plants. This current lack of merchant CT development in PJM raises the question of whether CTs may become less suitable as a reference technology to estimate Net CONE

³⁹ See Newell (2014a) Section II.B.

for VRR curve purposes, because it: (a) results in sparse availability of data on the technical specifications and cost drivers on the reference CT technology; and (b) may indicate that technology and market developments are trending such that CT plants are no longer economic for merchant investment compared to CC technology. It is also possible, however, that the current preference for merchant CC development reflects only a temporary disequilibrium due to currently-projected market conditions that make higher-efficiency, intermediate-load CC plants more economic.

Over the long-term, it should not matter which technology is selected for determining Net CONE as long as the chosen technology is economically viable. This is because in long-term market equilibrium expectations, the Net CONE value of all economically-viable generating technologies for new plants would be identical and equal to the market price for capacity. However, it would not be uncommon to find most markets in at least some level of disequilibrium at a given snapshot in time. In fact, changing market conditions will tend to introduce short- to intermediate-term deviations from long-term equilibrium in terms of total resource level and resource mix, such that prevailing market conditions temporarily make one technology more economic than other, with a lower Net CONE. Over time, however, these relative fluctuations in Net CONE values should average out and be the same for all technologies that are economically viable in the long-run.

It is important to recognize that CC and CT Net CONE estimates may fluctuate around the same long-term equilibrium value when selecting the reference technology for the VRR curve. First, because both CCs and CTs will sometimes have Net CONE values temporarily below their long-run average, it is important to avoid switching back and forth to the technology with the lowest Net CONE. Such an approach would understate the true cost of new entry for either technology when evaluated individually, and would result in the under-procurement of resources relative to the reliability target. Further, fluctuating Net CONE estimates may reflect not only temporary changes in market fundamental but also estimation errors, meaning that switching to technologies with the biggest downward errors would almost guarantee under-procurement. For similar reasons, it does not make sense to always switch to the technology with the highest Net CONE estimate.

For these reasons, maintaining a single reference technology over time can be expected to yield an accurate Net CONE value in expectation over time. However, doing so might lead to temporary over-procurement when the chosen technology becomes less viable for merchant entry because another technology has a lower Net CONE. A less obvious but more worrisome problem is that maintaining a single reference technology could lead to under-procurement when the reference technology yields Net CONE estimates that are substantially below its equilibrium value due to unusual market conditions or estimation errors. Thus, under temporary market conditions characterized by oscillations around long-term equilibrium market conditions, the technology with the temporarily-lowest Net CONE value might still need a capacity price above its administratively-estimated Net CONE value before entry is economically viable.

To account for these dynamics, it may be preferable to set Net CONE at an *average* of the Net CONE values of technologies that are most likely viable for merchant investments. Such an average would help stabilize capacity prices and resource adequacy through periodic short-term deviations from

long-run equilibrium and diversify the risk of estimation error associated with any single technology. If the averaging approach stay the same over time and incorporates multiple technologies that are both economically viable and have similar susceptibility to estimation error, then we would expect administrative Net CONE estimates to be more accurate and reflective of equilibrium conditions on average.

PJM can choose to move ahead with any of three reference technology options: (1) maintaining the current gas CT; (2) adopting a gas CC; or (3) adopting an average of the two. We summarize the advantages of each approach in Table 4, in each case considering that the reference technology should be one that: (a) is technically feasible to build; (b) is economically viable on a merchant basis; (c) has a relatively standard set of characteristics and costs, such that large quantities of similar units could be built (*e.g.*, which would exclude some low-cost unique opportunities such as DR and cogeneration); (d) has net costs that can be estimated with relatively small administrative estimation errors; and (e) is likely to remain a viable reference technology for many years.

Some of these considerations would support continuing to rely on the currently-used reference CT, including maintaining continuity in the market design. This avoids switching to other technologies that may temporarily have lower Net CONE values, and has the advantage that the smaller value of net E&AS revenues makes Net CONE values for CTs less dependent to E&AS-related estimation errors.

There are also important considerations that suggest that CC plants may be a more appropriate reference technology. First, natural-gas-fired CCs are being proposed and built in large numbers in PJM and elsewhere in the U.S. In contrast, very few CTs are being developed by merchant generators. Based on these “revealed preferences,” a CC plant would be the most logical choice of reference technology if there were no pre-existing approach and only one technology could be selected. Second, a switch to CCs as the reference technology may be justified because the lack of merchant CT development also creates doubt about whether the technology is well-suited for merchant investment. Third, because more CC plants are being developed, we have more and better information on the costs and characteristics of a new CC plants. And finally, if PJM and stakeholders decided to pursue and implement our recommendations to switch to a forward-looking E&AS offset, it would be easier to estimate that parameter accurately for CC than for CT plants. This is the case because available 5x16 forward prices are better-aligned with gas CC dispatch profiles, making it easier to determine forward-looking estimates for E&AS revenues.

Table 4
Selecting the Reference Technology to Estimate Net CONE for VRR Curve Purposes

Arguments for Gas CT	... for Gas CC	... for Average of CC and CT
<ul style="list-style-type: none"> • Existing reference technology (as prescribed by PJM tariff) • Continuity of market design will minimize price changes due to changes in administrative parameters • Frequent switching based on each year’s lowest Net CONE would under-procure if relative economics of technologies are switching • Lower absolute E&AS means its estimation error has lower impact 	<ul style="list-style-type: none"> • Predominant new build in PJM & US • Current 7FA CT may look good on paper (and recently accepted by FERC as feasible w/ SCR in NYISO), but why is no one building them? • Is there room for gas CTs going forward or do a combination of CCs and DR make them uneconomic? • More standardize technology and better cost information for estimating CONE • Easier to calculate forward-looking CC E&AS offset from 5x16 futures • E&AS not as widely varying among actual plants for idiosyncratic reasons 	<ul style="list-style-type: none"> • In the long run, all <u>economic</u> resource types should have the same Net CONE; makes sense to average if they are all economic for merchant entry • Averaging results in a closer-to-equilibrium estimate, as any one technology likely will be out of the money for temporary periods • Prevents problems from switching and reduces impact of administrative error of estimates • Will help mitigate impacts of volatile or uncertain E&AS estimates • Averaging for the next 4 years would provide continuity and time to observe whether predominance of CC builds is temporary or reflects a permanent change

Evaluating the advantages and disadvantages to choosing either a CC or a CT as the reference technology, we recommend that PJM consider adopting an approach that estimates Net CONE as the average of the CC and CT Net CONE estimates. As long as both technologies are economically viable, we believe that this averaging approach will provide a more stable and more accurate estimate of Net CONE by reducing the impact of CONE and E&AS revenue estimation errors and disequilibrium market conditions. However, we also acknowledge that it remains an open question whether the frame gas CT is an economically viable part of the resource mix, and so recommend re-evaluating this determination in the next CONE study four years from now. If additional market evidence becomes available showing that the CT will not be a viable technology for merchant entry over that period, then the two-technology average could be treated as a transitional step to relying exclusively on CCs as the reference technology. In that future evaluation, we would recommend considering the same factors that we have evaluated here and similarly avoid changing the approach unless it is clearly supported by market evidence.

E. RECOMMENDATIONS FOR NET COST OF NEW ENTRY

Although PJM’s administrative Net CONE estimates have likely been within a reasonable error band of the true value in most locations, recommend a series of modifications that could improve the accuracy and stability of these estimates in the future. We anticipate that the overall impact of these modifications would be largely offsetting, with some increasing and others decreasing Net CONE in individual locations. However, we believe implementation of our recommended modifications would result in a greater level of accuracy and stability of Net CONE estimates as market conditions change over time.

- 1. Adopt updated Gross CONE estimates.** We recommend updating the levelized Gross CONE to the numbers reported in Section III.A.1 for delivery year 2018/19, based on our concurrently-published study of the costs of building new gas CC and CT plants in PJM.⁴⁰
- 2. Adopt level-real Gross CONE values.** We recommend that PJM consider adopting a “level-real” (rather than the current “level-nominal”) approach to levelizing gross plant capital costs. As we explained in our 2011 review and reiterate now, we view a level-real capital cost recovery more consistent with the time profile over which most developers anticipate recovering their investment costs. This recommendation is contingent, however, on combining it with our recommendation to improve VRR curve’s anticipated reliability performance as discussed below.
- 3. Consider replacing the Handy-Whitman Index for annual CONE updates.** To escalate Gross CONE values annually between CONE studies, we recommend that PJM consider replacing the Handy-Whitman “Other” index with a weighted composite of wage, materials, and turbine cost indices from the Bureau of Labor Statistics. We believe such an approach would more accurately reflect industry cost trends that are the underlying drivers of changes to CONE.
- 4. Calibrate historical E&AS simulations against plant actuals.** We recommend further investigating why PJM’s simulated historical E&AS estimates exceed actual margins of CCs in all areas by roughly \$40,000/MW-yr and by roughly \$30,000/MW-yr for CTs in SWMAAC. Given the large discrepancies, we recommend that PJM compile a more detailed set of plant-specific cost and revenue data for representative units that can be used for such a calibration, and then adjust its historical simulation approach to develop E&AS numbers that are as reflective as possible of these actual plant data in each location. This adjustment would require identifying and accounting for factors that may be depressing actual net revenues below simulated levels, such as operational constraints, heat rate issues, differences in variable and commitment costs, or fuel availability. This analysis would inform how to develop more realistic simulations of E&AS margins, and avoid overstating E&AS offsets and understating Net CONE values, which risks procuring less capacity than needed to meet PJM’s resource adequacy objectives. To allow flexibility in this calibration exercise, we also

⁴⁰ See Newell (2014a).

recommend that PJM consider eliminating Tariff language specifying an exact ancillary service adder and variable operations and maintenance cost assumption, instead adopting assumptions that result estimates that are well-calibrated to plant actuals.

5. **Develop a forward-looking estimate of Net E&AS revenues.** An E&AS offset based on three years of historical prices can be easily distorted by anomalous market conditions that are not representative of what market participants' expect in the future RPM delivery year. The threat of significant distortions due to unusual historical market conditions has increased with PJM's new shortage pricing rules that will magnify the impact of shortages. For example, unusual weather or fuel market conditions can cause prices to spike, increasing E&AS revenues beyond what a generation developer would expect to earn in the future under more typical weather conditions. Historical prices are also 4 to 6 years out of date relative to a delivery period corresponding to a three-year forward Base Residual Auction and, therefore, may not be a good indicator of future market conditions. For these reasons, we recommend that PJM evaluate options for incorporating futures prices for fuel and electricity into this analysis, similar to the stakeholder-supported approach proposed to FERC by ISO-NE. Currently, such a forward-looking E&AS approach would likely produce results similar to three-year historical approach for the CT, but substantially below the historical approach for the CC (resulting in a similar CT Net CONE, but an increased CC Net CONE).
6. **Align CONE Areas more closely to modeled LDAs.** We recommend that PJM consider revising the definitions of CONE Areas to more closely align with the modeled LDAs, by: (a) using the *CONE Area 3: Rest of RTO* estimate for the system-wide VRR curve (rather than the current fixed value adopted in settlement); (b) using the *CONE Area 4: Western MAAC* estimate for the MAAC VRR curve (rather than taking the minimum of sub-LDA numbers); and (c) combining *CONE Area 5: Dominion* into *CONE Area 3: Rest of RTO*, given that the Area 5 estimate has not been used to date. The result would be to develop a total of only four Gross CONE estimates in future studies, one for each of the four permanent LDAs.
7. **Consider introducing a test for a separate Gross CONE for small LDAs.** We also recommend that PJM introduce a test to determine whether smaller LDAs should have a separate Gross CONE estimate. In general, such a separate estimate would only be needed if the small LDA is persistently import-constrained, shows little evidence of potential for new entry, and shows evidence of structurally higher entry costs (*e.g.*, because the reference technology cannot be built there).
8. **Align E&AS offset and Net CONE more closely to modeled LDAs.** The current approach calculates E&AS offsets based on prices in a single tariff-designated energy zone for each CONE Area. As a result, the E&AS offset that is applied to a specific LDA may not be calculated based on prices in that LDA, but on prices in the parent LDA, a sub-LDA, or an adjacent LDA, none of which would provide an accurate E&AS estimate for the LDA and thus may cause under- or over-stated Net CONE values. We recommend that each LDA's E&AS offset be estimated based on prices within that LDA. For large LDAs that cover many zones, such as RTO and MAAC, the E&AS offset could be based on an injection-weighted generation bus average locational marginal price across the LDA, or an average of zone-level

E&AS estimates weighted by the quantity of RPM generation offers from each zone in the last BRA.

- 9. Consider imposing the parent-LDA Net CONE value as a minimum for sub-LDA Net CONE values.** We recommend that PJM consider imposing a minimum Net CONE for sub-LDAs at the parent-LDA Net CONE value, either for all LDAs or at least for medium-sized or small LDAs (*i.e.*, for all LDAs smaller than MAAC or EMAAC). This recommendation would safeguard against errors and associated under-procurement in small LDAs. Such errors are more likely to occur in small LDAs, such as SWMAAC, which may have idiosyncratic conditions and small sample sizes for calibrating CONE and E&AS estimates, and where under-procurement has disproportionately high reliability consequences. Even if Net CONE were truly lower in a small LDA, imposing a “parent-minimum” constraint would avoid down-shifting the VRR curve and offsetting the locational investment signals created by E&AS prices. If PJM and stakeholders decide not to pursue this recommendation, it would at least be necessary to carefully investigate E&AS and CONE estimates whenever Net CONE values in import-constrained LDAs are substantially below the Net CONE estimates of the parent LDA, such as in SWMAAC where low historical Net CONE estimates were caused by inaccurately high E&AS estimates.
- 10. Consider adopting the average of CC and CT Net CONE values for defining the VRR Curve.** Rather than relying only on CT Net CONE estimates for defining the VRR curve, we recommend that PJM consider setting Net CONE based on the average of CC and CT Net CONE estimates. This would recognize that CC plants are the predominant technology under development by merchant generators (which increases the accuracy of Gross CONE estimates), while avoiding a complete switch away from the currently-defined CT reference technology.

IV. Monte Carlo Simulation Modeling Approach

The position, slope, and shape of PJM's VRR curve have important consequences for the performance of the capacity market in terms of realized reliability levels and price volatility. Revising the shape and slope of the curve would change the expected distribution of price and quantity outcomes from the market, but the magnitude of these effects is not obvious on inspection or with only a few years of historical experience. We, therefore, use a Monte Carlo model to simulate a distribution of price, quantity, and reliability outcomes that might be realized over many years under the current VRR curve or alternative curves. In this Section, we describe the primary components of this model, including our characterization of supply, demand, transmission, reliability, and locational auction clearing. We present simulation results under the current VRR curve and alternative curves under several scenarios in Sections V and VI below.

A. OVERVIEW OF MODEL STRUCTURE

To evaluate the performance of the VRR curve and alternative curves over the long term, we conduct a Monte Carlo simulation of 1,000 capacity market outcomes. This analysis allows us to estimate a distribution of price, quantity, and reliability outcomes under a particular curve, and review these outcomes in light of the performance objectives of the VRR curve and RPM as discussed in Sections V.A.1 and VI.A.1 below.

The Monte Carlo simulation model we developed for this analysis builds on the simulation model we developed to assist ISO-NE design a sloped demand curve and is similar to the model, originally developed by Professor Benjamin Hobbs, that was previously used to evaluate VRR curve performance.⁴¹ The model developed for this analysis adds important features to make the simulations more realistic and more applicable to RPM. We now simulate RPM performance within individual LDAs, while the previously-used Hobbs model was only a system-wide model not able to simulate reliability outcomes within individual LDAs. The current model also employs a realistic sloped supply curve that is calibrated to observed RPM outcomes and reflects the wide range of capacity resources bidding into the RPM market—such as retrofits to existing units, imports, demand response, and different types of new units. In contrast, the previously-used Hobbs model did not utilize a sloped supply curve and relied on CTs as the only technology that would ever be added to the market. Equally important, the size and standard deviation of “shocks” to supply and demand conditions utilized in our Monte Carlo simulations are calibrated to the size and standard deviations of shocks observed in PJM, both at the system and individual LDA level.

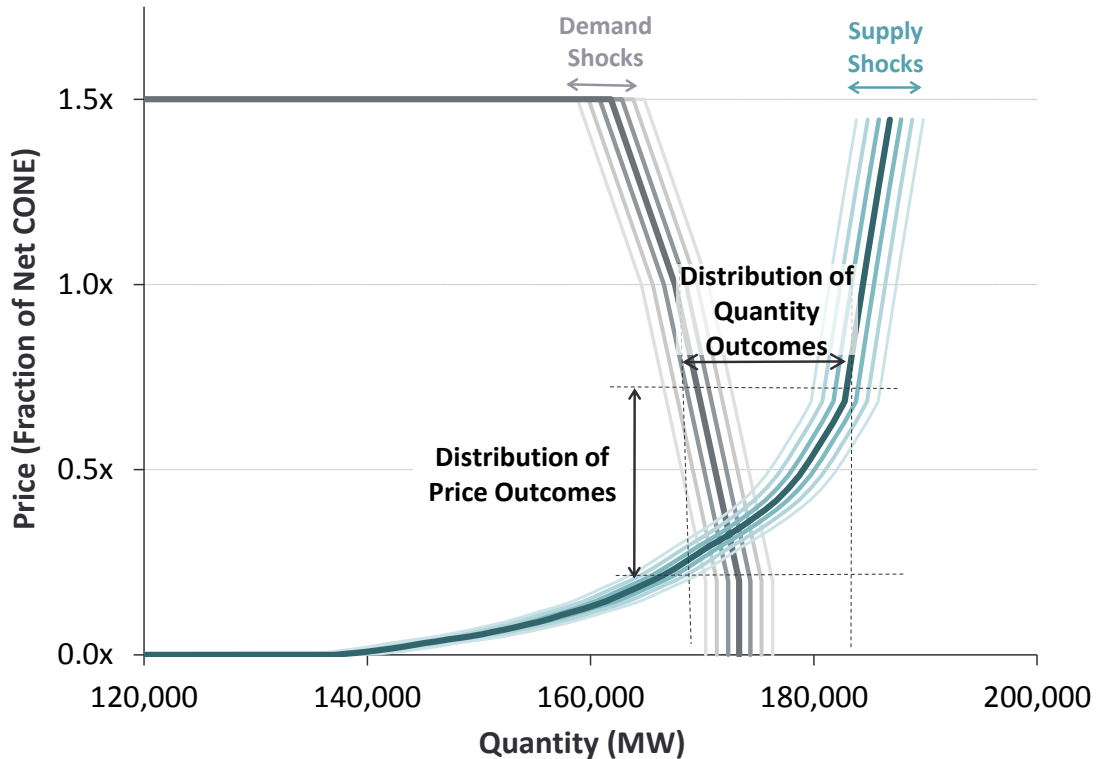
⁴¹ See discussion of the Hobbs simulation model in our 2008 and 2011 RPM Reports, Pfeifenberger (2008, 2011).

We use the planning parameters for delivery year 2016/17 as the basis for our modeling assumptions, combined with a historically-grounded locational supply curve to determine locational clearing prices and quantities. We then use historical market data to develop realistic shocks to supply, demand, and transmission in each draw. A stylized depiction of the price and quantity distributions driven by supply and demand shocks is shown in Figure 11, 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 new supply added infra-marginally until the long-term average price equals Net CONE.⁴² As such, our simulations reflect long-term conditions at economic equilibrium on average, and do not reflect a forecast of outcomes over the next several years or any other particular year. In our base case analysis, we model each draw from the model independently of the others, but we also conduct a sensitivity analysis incorporating time-sequential supply investments and auto-correlated loads.

⁴² 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.

Figure 11
Stylized Depiction of Supply and Demand Shocks in the Monte Carlo Analysis



Note:

Illustrative shocks are not intended to reflect exact shock magnitudes or locational clearing results.

Finally, we note three important simplifications to our modeling approach that reflect the scope of our assignment with PJM: (1) we analyze only the likely results of the three-year forward Base Residual Auctions (BRAs) and do not examine the short-term Incremental Auctions in terms of supply and demand changes that may occur between the BRA and IAs; (2) we do not evaluate the reliability or price implications of the 2.5% Short-Term Resource Procurement Target (STRPT), implicitly assuming that PJM will acquire exactly the targeted quantity in subsequent auctions; and (3) we do not evaluate the reliability implications or price interactions with PJM's multiple demand response (DR) product types. While these aspects of RPM, do have material importance for the performance of the curve in combination with the rest of the market design, these issues are not within the scope of the present analysis.

B. LOCAL SUPPLY AND DEMAND MODELING

In each simulation draw, we generate locational supply curves, locational demand curves, and transmission parameters. We then apply an optimal auction clearing algorithm to determine the cleared price and quantity in each location for that draw. The cleared quantity in each location then also determines the realized reliability outcome for each location. We describe here how we used historical market data to develop realistic representations of each of these components, consistent with the 2016/17 delivery year.

1. System and Local Supply Curves

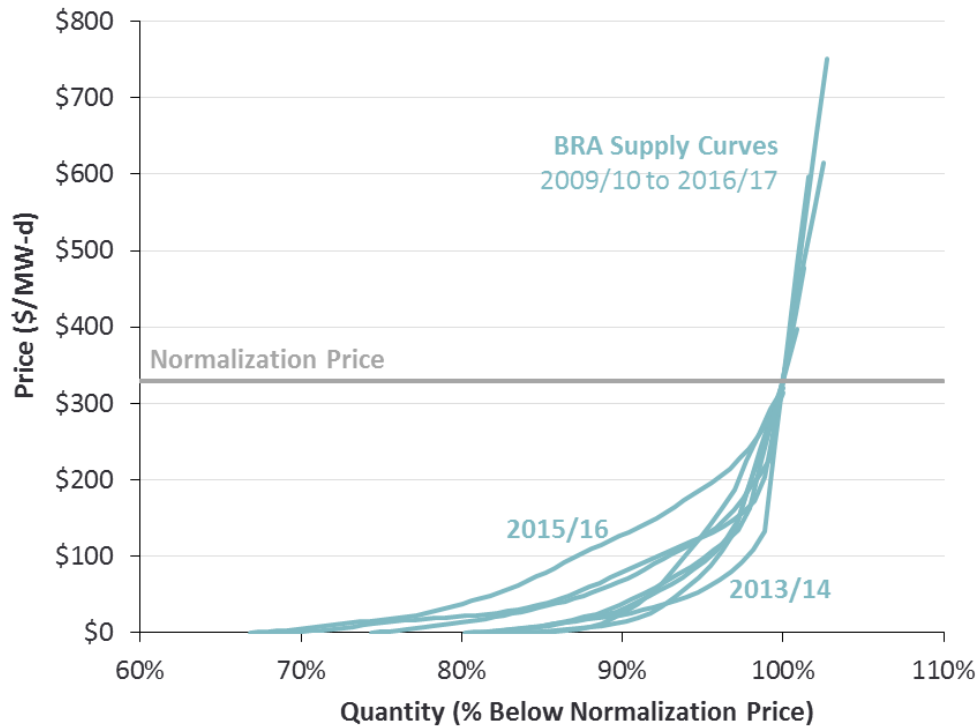
The supply curve shape is an important driver of volatility in cleared price and quantity in our modeling, as in real capacity markets. A gradually-increasing, elastic supply curve will result in relatively stable prices and quantities near the Reliability Requirement even in the presence of shocks to supply and demand, while a steep supply curve will result in greater volatility.

We use historical PJM offer prices and quantities to create eight realistic supply curve shapes, consistent with the supply curve shapes from the PJM BRAs conducted over 2009/10 to 2016/17.⁴³ To develop comparable supply curve shapes consistent with the 2016/17 delivery year, we escalate all offer prices to the 2016/17 delivery year and normalize the quantity of each curve by the quantity of offers below \$330 MW-d. Smoothed versions of the resulting supply curve shapes are presented in Figure 12, showing a range of shapes from the steepest curve in 2013/14 to the flattest or most elastic curves in 2014/15 and 2015/16, when many existing units offered at higher levels reflective of the expense of environmental retrofits.⁴⁴ However, in all years the supply curve becomes quite steep at high prices above \$300/MW-d, a fact that underpins the structural volatility of capacity markets in the real world as well as in our modeling.

⁴³ 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.

⁴⁴ 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 12
Individual Supply Curve Shapes used in Monte Carlo Analysis



Sources and Notes:

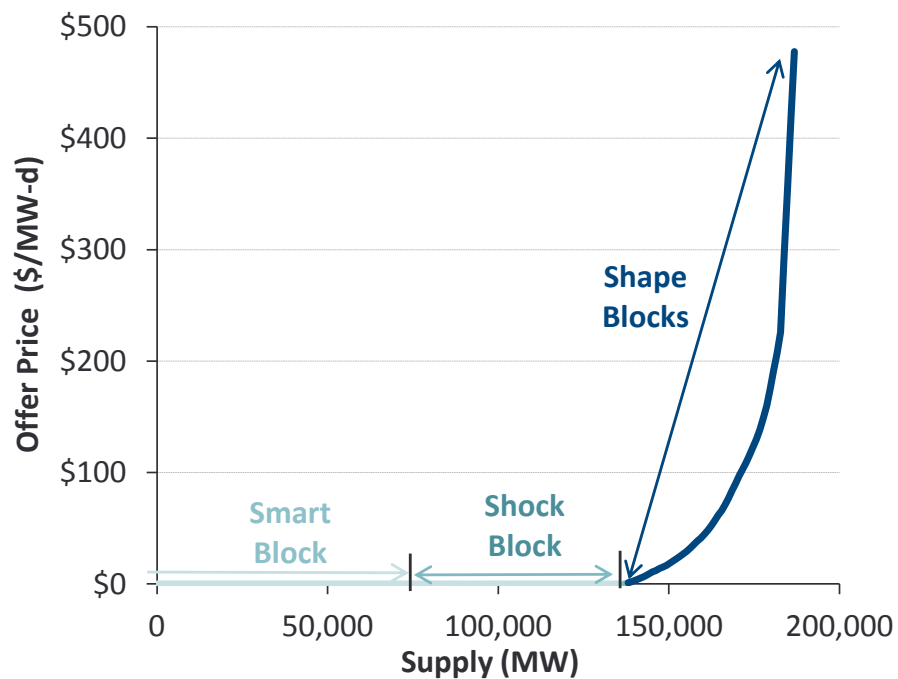
Smoothed supply offer curves developed from raw data provided by PJM staff.
 Offer curves normalized by quantities offered below \$330/MW-d and inflated to 2016/17 dollars.

We reflect the lumpy nature of investments by simulating each supply curve as a collection of discrete sized offer blocks. Simply modeling a smooth offer curve, like one of the individual smoothed curves shown in Figure 12, 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 2016/17 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. The result is that average prices will always equal Net CONE under all different demand curves, although differently-shaped demand curves will result in a different average cleared quantities. This normalization allows us to examine the performance of the VRR curve in a long-term equilibrium state. Too much zero-priced supply would result in an average price below Net CONE, while too little supply would result in a price above Net CONE.

We provide a stylized depiction of these supply curve components in Figure 13. The block of zero-priced supply used for normalization is shown as the “Smart Block,” and is held constant across the 1,000 individual draws we report, but is slightly different between demand curves.⁴⁵ For example, with a right-shifted demand curve, more supply would be included in the smart block (if the same smart block were used to model both curves, then clearing prices with the right-shifted curve would be higher than with our proposed curve). In contrast to the smart block, the quantity of the shock block varies with each draw to generate shocks to the supply curve, as described in Section IV.C below. Finally, the “Shape Blocks” are the collection of offers at above-zero prices generated using historical BRA offer data as described above.

Figure 13
Stylized Depiction of Simulated Supply Curve Components



Sources and Notes:

Smart block and shock blocks both represent quantities of supply that are offered at zero-price, and are used as adjustable parameters in our model.

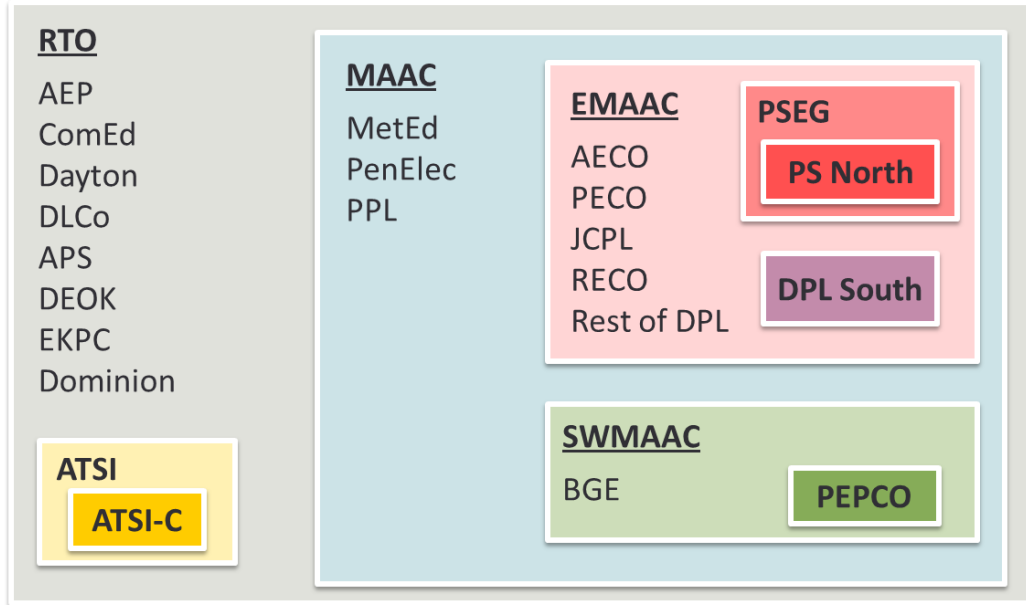
Shape blocks represent the supply that is offered at non-zero prices, and is based on historically observed supply as shown in Figure 12.

⁴⁵ 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 “Shock 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. Administrative Demand, Transmission, and Auction Clearing

We reflect administrative demand curves at both a system and local levels in a locational clearing algorithm that minimizes capacity procurement costs subject to transmission constraints. We reflect the nested zonal structure of PJM’s capacity market, consistent with the planning parameters for the 2016/17 delivery year, as shown schematically in Figure 14.

Figure 14
Nested Zonal Structure Consistent with 2016/17 BRA



Source:

Each rectangle and bold label represent an LDA modeled in 2016/17 BRA; individual load zones that are not modeled in RPM auctions are not bold, see PJM (2013a) and (2014a).

Note that the chart is slightly different from Figure 3 above because the prior figure reflects the subsequent delivery year after which three additional LDAs are modeled.

3. 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 results that PJM used to calculate the system and local Reliability Requirements for delivery year 2016/17, and as described in their reliability studies.⁴⁶ In that simulation analysis, PJM estimates the relationship between the supply quantity and LOLE, with system-wide Reliability Requirement set at the quantity needed to meet an LOLE of 0.1 Events/Yr (or 1-in-10) and local Reliability Requirements set at an LOLE of 0.04 Events/Yr (or 1-in-25).⁴⁷

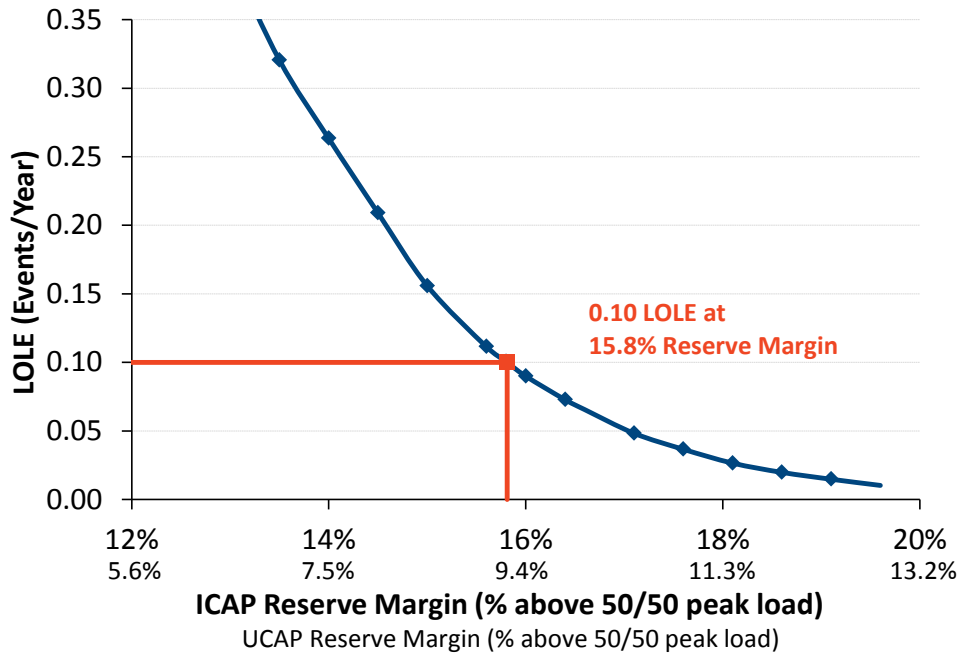
Figure 15 shows the relationship between the system reserve margin and LOLE. This relationship is asymmetrical, with reliability outcomes deteriorating sharply at reserve margins below the Reliability Requirement but improving only gradually at reserve margins above the Reliability Requirement. An important 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.⁴⁸

⁴⁶ See PJM (2013f).

⁴⁷ Note that the local requirement of 1-in-25 actually reflects lower total reliability, because the location is subject to not only local shortages but also system-wide shortages.

⁴⁸ 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.

Figure 15
LOLE vs. Reserve Margin



Sources and Notes:

LOLE data provided by PJM staff, with interpolation between discrete points.

C. SHOCKS TO SUPPLY, DEMAND, AND TRANSMISSION

To simulate a realistic distribution of price, quantity, and reliability outcomes, we introduce upward and downward shocks to supply, demand, administrative Net CONE, and transmission, with the magnitude of the shocks based on historical observation. Because the magnitude of these shocks is an important driver of the performance of the VRR curve, we also report the sensitivity of the VRR curve’s performance to each type of shock and conduct a sensitivity analysis regarding overall shock sizes in Sections V.B.2 and VI.B.4 below. We briefly describe here our approach to estimating shocks reflective of historical market data, and provide additional detail supporting these estimates in Appendix A. We also compare our resulting shock estimates to historically-observed values in Table 5 below.

- **Supply Offer Quantity:** We estimate shocks to supply offer quantities using the total quantity of supply offers in each location in each historical BRA, estimating the standard deviation in supply offers between years as a function of LDA size. See detail in Appendix A1.
- **Demand:** We model demand shocks in two components: (1) shocks to the load forecast, estimated at a standard deviation of 0.8% of the peak load forecast for the RTO, with each LDA having an RTO-correlated shock in addition to an uncorrelated load forecast shock; and (2) shocks to the Reliability Requirement as a percentage of system or local peak load. See detail in Appendix A2.

- **Administrative Net CONE:** We assume that administrative Net CONE is equal to true Net CONE on average under base case assumptions, but that administrative Net CONE is subject to random error around this expected value. We estimate the shock to administrative net CONE in each simulation considering: (a) shocks to Gross CONE, based on historical variation in the Handy Whitman index, and (b) shocks to one-year historical E&AS estimates, and (3) overall shocks to administrative Net CONE calculated as Gross CONE minus a three-year average of historical E&AS estimates. See detail in Appendix A3.
- **Capacity Emergency Transfer Limit:** We simulate shocks to CETL as normally distributed with a standard deviation of 12% of the expected CETL value based on the 2016/17 parameter, with the standard deviation estimated based on historical auction data across all locations and years. See detail in Appendix A4.

The aggregate impact of these individual shocks is illustrated in Table 5, where we compare historical shocks to supply, demand, and transmission (top two panels) against our simulated shocks (bottom panel). The most important comparison in this table is in “net supply,” calculated as supply plus CETL minus reliability requirement. This net supply comparison is the most important driver of price and quantity results in our modeling as well as in historical market results. Net supply is also the most important comparison, because it accounts for correlations between supply and demand that may exist, for example, because: (a) supply and demand are both increasing over time; (b) the total scope of RPM has expanded over time because of territory expansions and incorporation of FRR entities into RPM; and (c) suppliers may anticipate market conditions and pro-actively increase (decrease) offer quantities when there is anticipated increase (decrease) in demand.⁴⁹

We report historical shocks in two ways: (1) as a simple standard deviation of the actual historically observed values, and (2) as a standard deviation of the differences between the absolute observed values and a simple linear time trend over time. The first method produces larger shocks 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, because the absolute-value approach may over-estimate shocks for components with a substantial time trend (*e.g.*, in load forecast and total supply), while the deviation-from-trend approach may underestimate shocks for components that we would not expect to change substantially over time (*e.g.*, CETL and net supply minus demand). For these reasons, we base our modeling on simulated net supply shocks that fall between these two methods, but also test the sensitivity of our results to a reasonable uncertainty range.

⁴⁹ These correlations between supply and demand shocks, particularly related to FRR integration and RTO expansions, are the reason that gross supply and demand shocks are so much larger than the net supply shocks calculated historically. While these FRR integrations and expansions do introduce some amount of additional volatility in net supply, it is far less than if the same magnitude of supply and demand shocks were introduced on a non-correlated basis.

Table 5
Net Supply minus Demand Shocks

LDA	Standard Deviation				Standard Deviation as % of 2016/17 LDA Size			
	Supply	CETL	Reliability Requirement	Net Supply	Supply	CETL	Reliability Requirement	Net Supply
	(MW) [1]	(MW) [2]	(MW) [3]	(MW) [4]	(%) [5]	(%) [6]	(%) [7]	(%) [8]
Historical Absolute Value								
RTO	20,040	n/a	14,783	5,894	12.1%	n/a	8.9%	3.5%
MAAC	3,549	811	931	3,480	4.9%	1.1%	1.3%	4.8%
EMAAC	1,900	721	645	2,451	4.8%	1.8%	1.6%	6.2%
SWMAAC	907	910	335	1,652	5.2%	5.3%	1.9%	9.5%
PS	820	352	288	832	6.4%	2.7%	2.2%	6.5%
PS NORTH	534	252	101	585	8.3%	3.9%	1.6%	9.1%
DPL SOUTH	112	206	57	282	3.5%	6.5%	1.8%	8.9%
PEPCO	423	1,060	233	1,673	4.7%	11.8%	2.6%	18.6%
ATSI	717	1,742	38	2,421	4.4%	10.7%	0.2%	14.9%
ATSI-Cleveland	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Historical Deviation from Trend								
RTO	4,816	n/a	4,850	2,147	2.9%	n/a	2.9%	1.3%
MAAC	1,229	808	792	2,208	1.7%	1.1%	1.1%	3.1%
EMAAC	1,102	717	578	2,091	2.8%	1.8%	1.5%	5.3%
SWMAAC	409	378	283	792	2.4%	2.2%	1.6%	4.6%
PS	657	329	96	759	5.1%	2.6%	0.7%	5.9%
PS NORTH	338	222	84	401	5.3%	3.4%	1.3%	6.2%
DPL SOUTH	70	172	48	193	2.2%	5.4%	1.5%	6.1%
PEPCO	234	236	166	585	2.6%	2.6%	1.8%	6.5%
ATSI	557	n/a	n/a	n/a	3.4%	n/a	n/a	n/a
ATSI-Cleveland	473	n/a	n/a	n/a	7.7%	n/a	n/a	n/a
Simulation Shocks								
RTO	4,054	n/a	1,499	4,277	2.4%	n/a	0.9%	2.6%
MAAC	2,767	794	794	2,984	3.8%	1.1%	1.1%	4.1%
EMAAC	1,591	1,090	492	1,954	4.0%	2.7%	1.2%	4.9%
SWMAAC	644	1,074	279	1,214	3.7%	6.2%	1.6%	7.0%
PS	363	804	215	908	2.8%	6.2%	1.7%	7.1%
PS NORTH	226	359	131	446	3.5%	5.6%	2.0%	6.9%
DPL SOUTH	97	232	76	259	3.1%	7.4%	2.4%	8.2%
PEPCO	328	837	220	935	3.6%	9.3%	2.4%	10.4%
ATSI	663	963	259	1,186	4.1%	5.9%	1.6%	7.3%
ATSI-Cleveland	157	641	164	699	2.5%	10.4%	2.7%	11.3%

Sources and Notes:

All values calculated over 2009/10 through 2016/17 delivery years, where data were available.

[1]: Historical standard deviations calculated from annual BRA Supply Offers, see Appendix A1.

[2]: Historical standard deviations calculated from CETL values in the PJM Planning Parameters., see Appendix A4.

[3]: Historical standard deviations from Reliability Requirement values in the PJM Planning Parameters, see Appendix A2.

[4]: All standard deviations are calculated based on Net Supply, where Net Supply equals [1] + [2] – [3].

[5] – [8]: Equal to columns [1] – [4], divided by the LDA’s 2016/17 Reliability Requirement.

D. SUMMARY OF BASE CASE PARAMETERS AND INPUT ASSUMPTIONS

Table 6 summarizes the base case input assumptions that we apply in our Monte Carlo simulation exercise. We adopt the Reliability Requirement, CETL, and Net CONE parameters from the administrative parameters from the 2016/17 BRA, and assume that the true developer Net CONE is equal to the administratively-estimated Net CONE. We also report the standard deviation of shocks to each of these parameters as generated across 1,000 simulation draws.

Table 6
Base Case Parameters and Input Assumptions

Parameter		RTO	ATSI	ATSI-C	MAAC	EMAAC	SWMAAC	PSEG	DPL-S	PS-N	PEPCO
Average Parameter Value											
Administrative Net CONE	(\$/MW-d)	\$331	\$363	\$363	\$277	\$330	\$277	\$330	\$330	\$330	\$277
True Net CONE	(\$/MW-d)	\$331	\$363	\$363	\$277	\$330	\$277	\$330	\$330	\$330	\$277
CETL	(MW)	n/a	7,881	5,245	6,495	8,916	8,786	6,581	1,901	2,936	6,846
Reliability Requirement	(MW)	166,128	16,255	6,164	72,299	39,694	17,316	12,870	3,160	6,440	9,012
Standard Deviation of Simulated Shocks											
Administrative Net CONE	(\$/MW-d)	\$26	\$23	\$23	\$37	\$34	\$37	\$34	\$34	\$34	\$37
Reliability Requirement	(MW)	1,499	259	164	794	492	279	215	76	131	220
Reliability Requirement	(% of RR)	0.9%	1.6%	2.7%	1.1%	1.2%	1.6%	1.7%	2.4%	2.0%	2.4%
CETL	(MW)	n/a	965	662	771	1,055	1,008	793	230	364	844
Supply Excluding Sub-LDAs	(MW)	624	507	157	532	1,132	315	136	97	226	328
Supply Including Sub-LDAs	(MW)	4,054	663	157	2,767	1,591	644	363	97	226	328
Net Supply	(MW)	4,277	1,186	699	2,984	1,954	1,214	908	259	446	935

Sources and Notes:

Average Parameter Values are from 2016/17 PJM Planning Parameters, see PJM 2013a.

Details on Standard Deviation of Simulated Shocks are provided in Appendix A.

V. 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 reliability standard. The curve also 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. In this Section of the report, we evaluate the VRR curve by: (1) laying out the VRR curve design objectives against which we evaluate the curve; (2) qualitatively reviewing its likely performance, as indicated by the curve shape, quantity at the price cap, and width; and (3) estimating the distribution of price, quantity, and reliability outcomes under the curve. This evaluation 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 VI.

Based on this evaluation, we identify potential performance concerns including a relatively high frequency of low-reliability events and realized reliability below the 1-in-10 standard on a long-term average basis. To address these concerns, we recommend revising the VRR curve by adopting a revised convex VRR curve shape that would address these performance concerns, with parameters that are tuned to meet the 1-in-10 standard.

A. QUALITATIVE REVIEW OF THE CURRENT SYSTEM CURVE

We begin our evaluation of the system VRR curve by laying out an explicit set of design objectives, with the primary objective being to achieve the 1-in-10 reliability standard on a long-term average basis. We then qualitatively assess the likely performance of the VRR curve by examining the curve shape, reliability at the price cap, and VRR curve width compared to the likely size of year-to-year shocks in supply and demand.

1. System-Wide Design Objectives

The primary design objective of the system-wide VRR curve is to procure enough resources to maintain resource adequacy, including through merchant entry when needed. This objective must be fulfilled while also 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.⁵⁰

⁵⁰ See Weitzman (1974).

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. 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:
 - 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.
 - 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 under certain conditions.⁵¹
 - 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 reduce price volatility if possible. 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, concerns about market power are also

⁵¹ Specifically, if the BRA clears a quantity less than IRM-1% for three consecutive years. See PJM (2014b), Section 16.3.

supported by having a moderate price cap that limits the price impact of withholding.

- On the other hand, 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 also 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.⁵²
- 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 estimates, although adjustments may be necessary to accommodate changes in market and system conditions.
 - To support stability and transparency, the VRR curve should also be simple in its definition and in how parameters are updated over time. This can also avoid stakeholder contentiousness and litigation, which would increase regulatory risk for investors.

Several of these design objectives are inherently difficult to satisfy, 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 will mitigate 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 further explain the tradeoffs among these design objectives as we evaluate the performance of the VRR curve and potential changes to the curve.

⁵² 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.

We also note that 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 itself from reliability and economic perspectives, this is not within the scope of our present analysis.⁵³

2. Shape of the VRR Curve

PJM's VRR curve has a concave shape (*i.e.*, pointing away from the intersection of the x- and y-axis) defined by three points as described in Section II.C above. The overall price and quantity placement of the VRR curve are consistent with PJM's design objectives, with prices above Net CONE when the system would be below the resource adequacy requirement and prices below Net CONE when the system exceeds the resource adequacy requirement by more than IRM+1%. This price and quantity relationship should work to attract new capacity investments when the system is short, and postpone such investments when the system is long. The downward-sloping shape of the curve will also work to mitigate against price volatility and the exercise of market power, consistent with the design objectives. However, the concave shape of the VRR curve may not meet PJM's design objectives as well as alternative shapes such as straight-line or convex curves, a topic that we evaluate qualitatively here and quantitatively in subsequent sections.

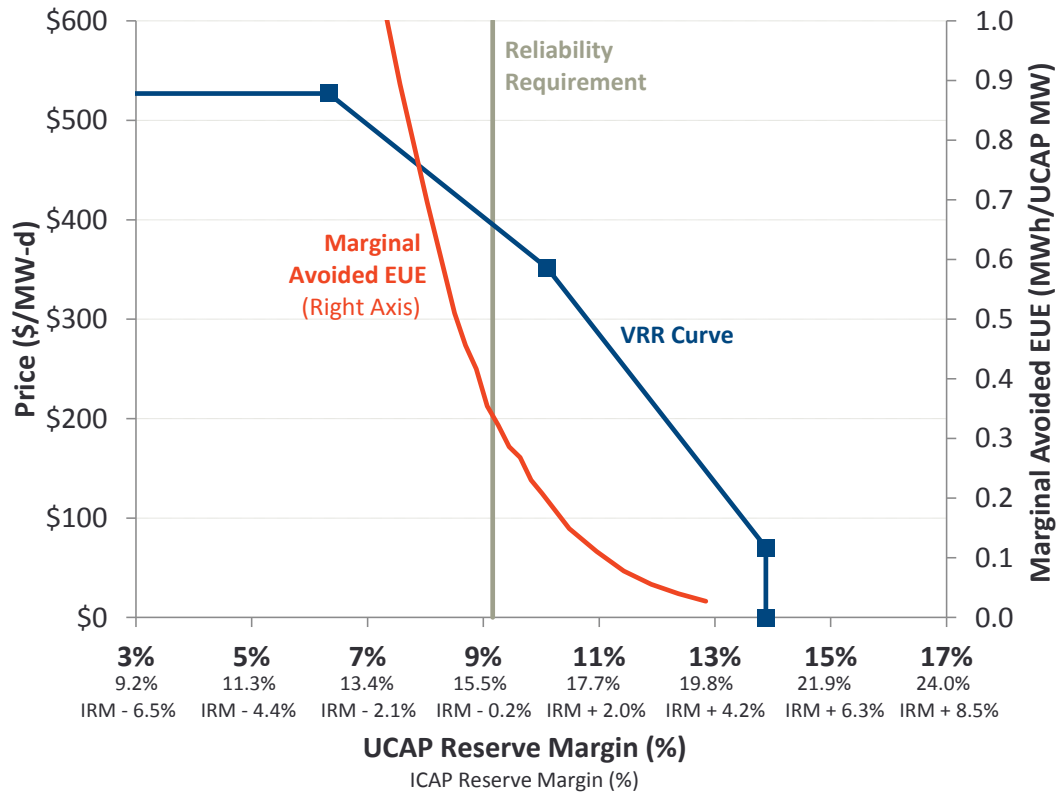
An important theoretical disadvantage of the existing concave curve is that it is not consistent with the incremental reliability and economic value of capacity, as illustrated in Figure 16. The figure shows the VRR curve superimposed over the marginal avoided expected unserved energy (EUE), which measures 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. This *convex* shape will also reflect the economic value of adding capacity at varying reserve margins, although the total economic value of capacity also includes components other than avoided EUE, such as other avoided emergency events, avoided DR dispatch, and avoided dispatch of high-cost resources.⁵⁴

For these reasons, moving from a concave to a convex shape would move toward one of PJM's secondary objectives of rationalizing prices according to incremental reliability value. However, we note that attempting to make the curve exactly proportional to this avoided EUE line is not advisable from a price volatility perspective, because this curve is much steeper than the current VRR curve and would not reflect the volatility-mitigation benefit of a more sloped curve.

⁵³ For example, see Pfeifenberger (2013).

⁵⁴ See Pfeifenberger (2013).

Figure 16
2017/18 RTO VRR Curve Compared to Marginal Avoided EUE



Sources and Notes:

Current VRR Curve reflects the system VRR curve in the 2016/2017 Planning Parameters, PJM (2013a.)
 Marginal Avoided EUE equal to LOLH times 1 MW.

A convex-shaped curve would also tend to produce a distribution of market prices that would be 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. However, as we illustrate quantitatively in the following sections, we find that convex curves also lead to slightly more price volatility than would a straight-line curve or concave curve due the steeper shape in the high-price region of the demand curve, which is magnified by steep supply curves. Additionally, combining a convex curve with PJM’s relatively low price cap of 1.5× Net CONE can have the undesirable consequence of increasing the frequency of price-cap events unless the curve is relatively flat.

3. Reliability at the Price Cap

The curve can also 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 Reliability 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+1% changes LOLE from 0.10 to 0.06 events per year, while decreasing the reserve margin to IRM-1% changes LOLE from 0.10 to 0.18 events per year. A 1 percentage point decrease of reserve margin thus has an impact on reliability that is twice as large as the impact of a 1 percentage point increase, and this asymmetry is even greater for larger deviations.

By comparison, the current VRR curve is *less* steep below the Reliability Requirement, with prices increasing by only \$41.32/MW-d or 7% between IRM and IRM-1%, although anticipated outage events increase by 79% over that range. The reliability impact becomes even greater at lower reserve margins, with LOLE increasing to 0.43 events per year, or a reliability index of 1 event in 3.37 years by the time prices reach the maximum value at point “a”. This indicates that the flat shape of the current VRR curve at low reserve margins puts the region at a greater risk of low reliability events. In fact, to produce prices equal to Net CONE on average, and with a cap at the moderate level of 1.5× Net CONE, we would expect a relatively high frequency of relatively low reliability events (an expectation that we confirm through simulation estimates in Section V.B below).

To reduce the frequency of such low reliability events, we recommend that PJM consider right-shifting the quantity at point “a” as well as also possibly increasing the price cap. In terms of quantity, we recommend that PJM revise this parameter consistent with its administrative reliability backstop practices, such that PJM would attempt to procure all available resources through capacity market auctions before triggering any backstop auctions or out-of-market procurement. The only such practice that is currently codified in the Tariff is PJM’s Reliability Backstop Auction trigger, which states that PJM must conduct a backstop procurement if the BRA should ever clear below a quantity of IRM-1% for three consecutive years.⁵⁵ This IRM-1% threshold is consistent with a reliability index of 1-in-5.6, as summarized in Table 7 in comparison with other quantity points. This suggests that the appropriate quantity at the price cap should be at least IRM-1%. Specifically, we recommend increasing point “a” to the quantity that produces a reliability index of 1-in-5 (rather than a fixed distance from IRM) to ensure that the reliability implications of this point are robust to changes in system conditions.

⁵⁵ See PJM (2014b).

Table 7
Reliability at VRR Curve Quantity Points and Backstop Trigger

Quantity Point	LOLE (Ev/Yr)	Reliability Index (1-in-X)
Point "a" at IRM - 3%	0.42	1-in-2.4
Backstop Trigger at IRM - 1%	0.18	1-in-5.6
Reliability Requirement at IRM	0.10	1-in-10.0
Point "b" at IRM + 1%	0.06	1-in-17.9

Notes:

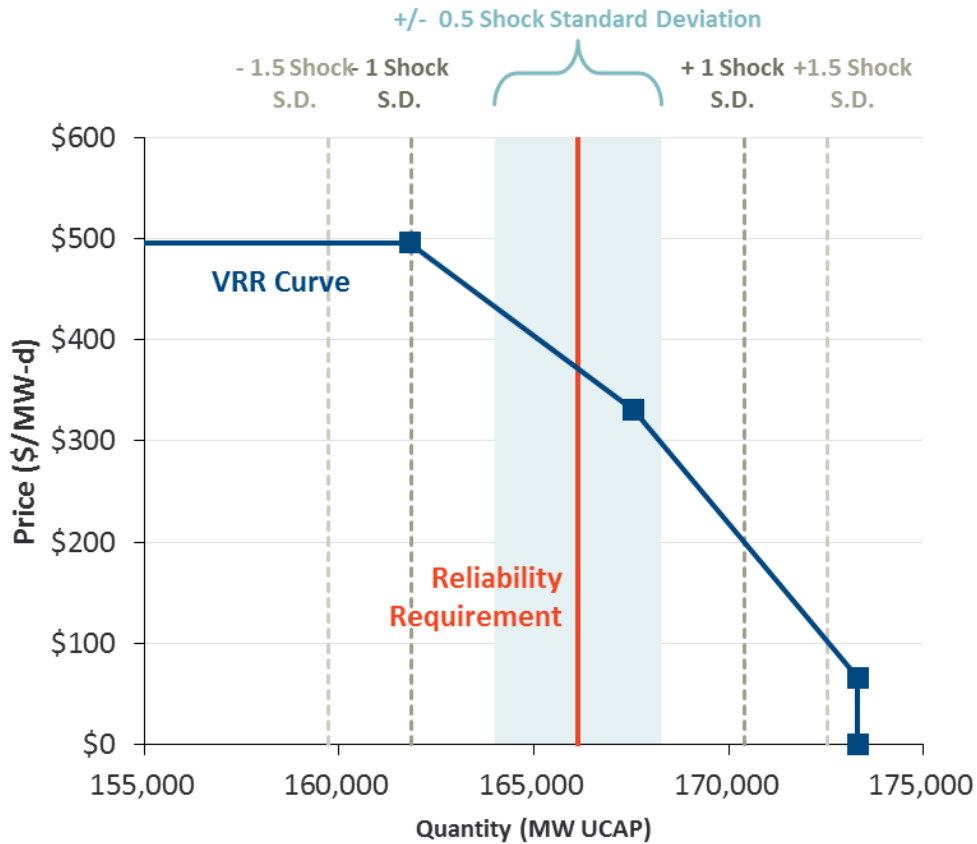
Loss of Load Event (LOLE) shows the corresponding reliability for each quantity outcome shown, based on an exponential fit of LOLE and quantity as a percentage of Reliability Requirement.
Reliability Index is the reciprocal of LOLE.

4. VRR Curve Width Compared to Net Supply Shock Sizes

Another important driver of the curve’s performance is the width of the curve compared to year-to-year shifts in supply and demand. Capacity markets are structurally volatile, primarily because the supply curve is quite steep at high prices. (In contrast, the flat slope of the supply curve provides meaningful volatility mitigation benefits in the low price range). 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 shocks to supply and demand.

Figure 17 shows the VRR curve width compared to typical expected net supply shocks as estimated in Section IV.C above. We find that the net supply minus demand balance can be expected to change by a relatively substantial quantity each year, with a standard deviation of 3% of the Reliability Requirement or 4,277 MW total using 2016/17 parameters. These relatively large shocks to supply and demand 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, with the most important example being the 2014/15 MATS regulation which introduced a substantial number of retirements over a small number of years; (c) rule changes, that have resulted in increased or decreased offer quantities from categories of resources such as demand response and imports; (d) the economic recession that began in Year, 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 shock into the market.

Figure 17
VRR Curve Width Compared to Expected Net Supply Shocks



Sources and Notes:

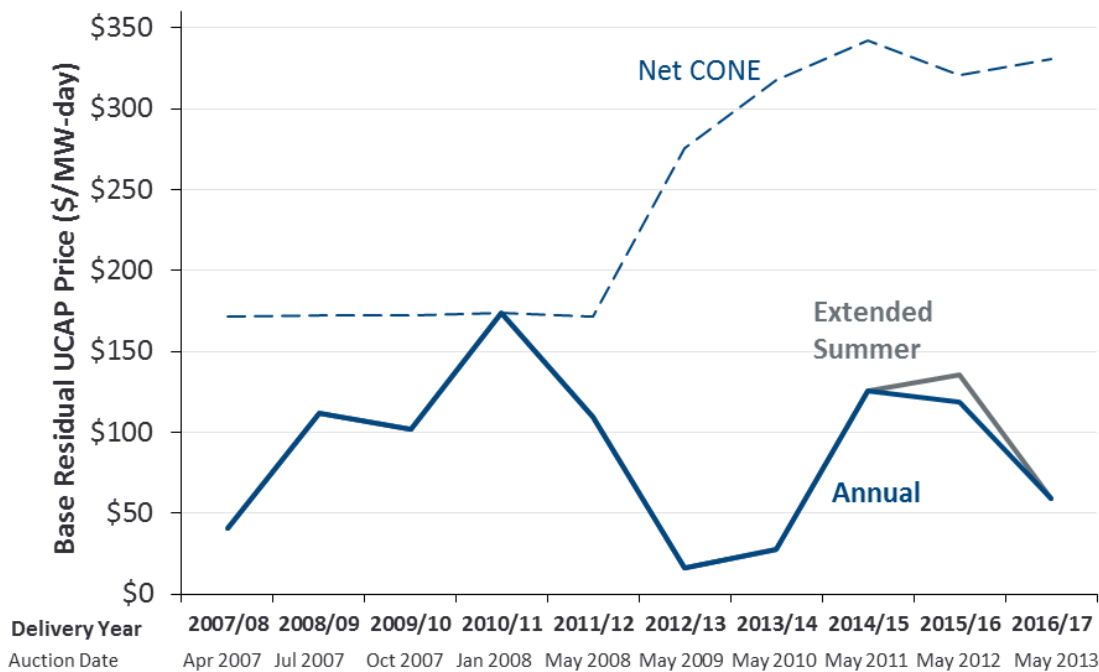
The range of expected net supply shocks are based on simulated outcomes of supply minus demand shocks for the system. As reported in Table 5, the standard deviation of simulated shocks is 4,277 MW.

These relatively large year-to-year changes in net supply minus demand balance are relatively large compared to the width of the VRR curve. As Figure 17 shows, if starting at the Reliability Requirement, losing one standard deviation of supply would increase prices to the cap, or by a delta of \$123/MW-d or 37% of Net CONE; while adding one standard deviation of supply would decrease prices by \$172/MW-d or 52% of Net CONE. The magnitude of expected shifts to net supply balance also 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 net supply shocks, we would expect quantities at IRM-1% (reliability index 1-in-5.6) approximately once every 2.7 years and at IRM-3% (reliability index 1-in-2.4) approximately once every 6.4 years.

The consequence of these relatively large deviations in net supply and demand balance, combined with the current VRR curve, is that RPM has produced relatively volatile price outcomes, as shown in Figure 18. These volatile price outcomes have been the source of substantial concern to market participants, introducing substantial uncertainty into business decisions. However, supply shocks have not historically resulted in low realized reserve margins, largely because RPM was initiated at a

time of relative supply excess and is only now approaching (but has not reached) long-run equilibrium reserve margins.

Figure 18
Historical BRA Capacity Prices for Rest of RTO



Sources and Notes:

PJM Base Residual Auction Reports and Planning Parameters. See PJM (2007 – 2013a.)

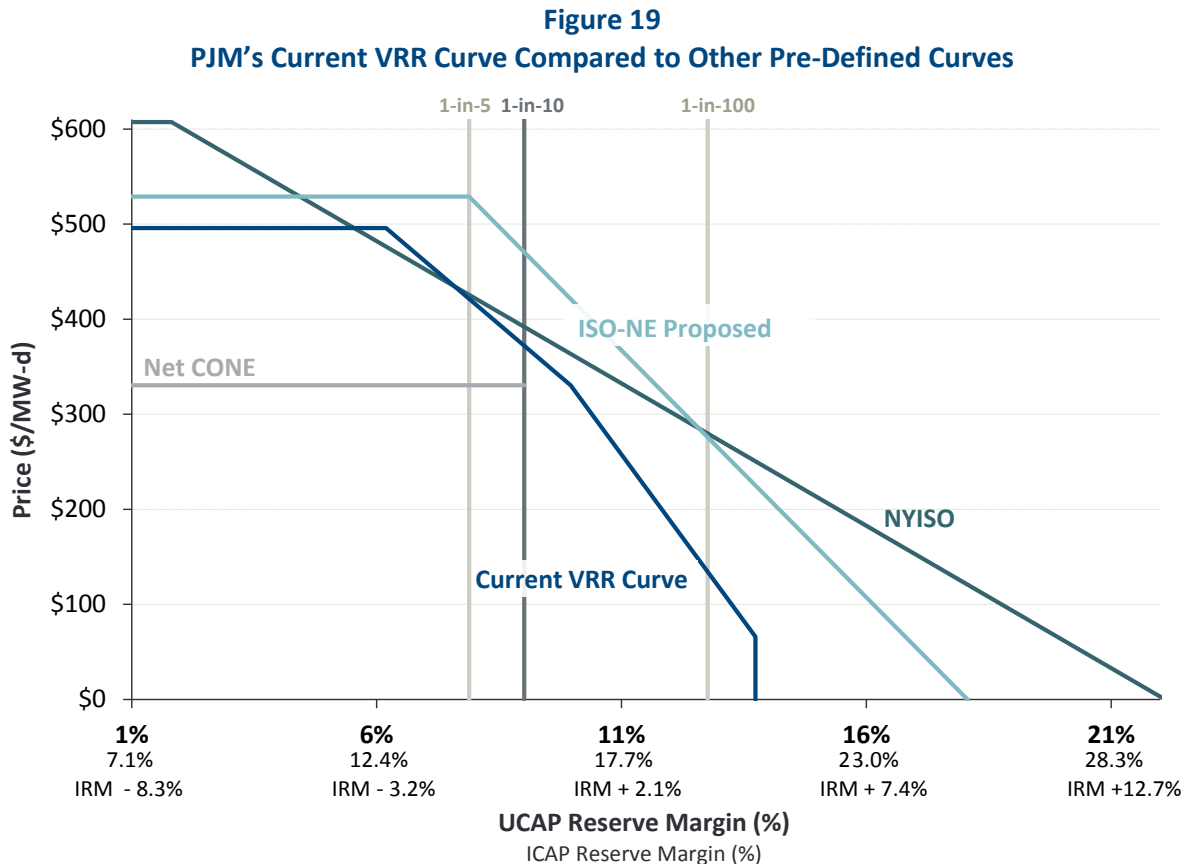
Together, these factors suggest that it may be beneficial to increase the width of the VRR to provide some additional volatility mitigation benefit, or to right-shift the curve to protect against very low future reliability outcomes. However, both of these potential revisions would come at a cost. Widening or flattening the curve would reduce price volatility, with a tradeoff of increasing quantity uncertainty. Right-shifting the curve would increase realized reserve margins and reliability, but at the expense of increased capacity procurement costs. We more fully examine these options and quantify their tradeoffs using probabilistic simulations of these various outcomes in the following sections.

B. SIMULATED PERFORMANCE OF THE CURRENT SYSTEM CURVE

In this Section, we use the probabilistic modeling approach described in Section 10 above to estimate the likely distribution of price, quantity, and reliability outcomes that the current VRR curve will achieve. We also conduct a sensitivity analysis evaluating the performance of the curve under different modeling assumptions, higher and lower Net CONE values, and in the presence of administrative errors in the Net CONE estimate. All analyses reflect long-term equilibrium conditions in which annual outcomes fluctuate but the long-term average price equals (true) Net CONE. These long-term analyses are not intended to reflect current or near-term market conditions.

1. Performance of VRR Curve Compared to other Pre-Defined Curves

We start by presenting summary statistics describing the distribution of price, quantity, and reliability outcomes that we simulate under Base Case assumptions for PJM’s current VRR Curve. To provide benchmark reference points to compare to, we also compare these results to three other curves as shown in Figure 19: (1) a vertical curve with the same price cap; (2) NYISO’s ICAP demand curve; and (3) ISO-NE’s recently-proposed capacity demand curve that is currently bending before FERC.



Sources and Notes:

ISO-NE and NYISO curves reported using those markets’ price and quantity definitions in most cases, but relative to PJM’s estimate of 2016/17 Net CONE, Reliability Requirement, and 1-in-5 quantity point for the PJM system. Current VRR Curve reflects the system VRR curve in the 2016/2017 PJM Planning Parameters, calculated relative to the full Reliability Requirement without applying the 2.5% holdback for short-term procurements, PJM (2013a). For NYISO Curve the ratio of reference price to Net CONE is equal to 1.185 and is consistent with the 2014 Summer NYCA curve, see NYISO (2014a) and (2014b), Section 5.5. ISO-NE Curve shows parameters proposed in April 2014 with cap quantity adjusted to 1-in-5 as estimated for PJM, see Newell (2014b), pp 10-12.

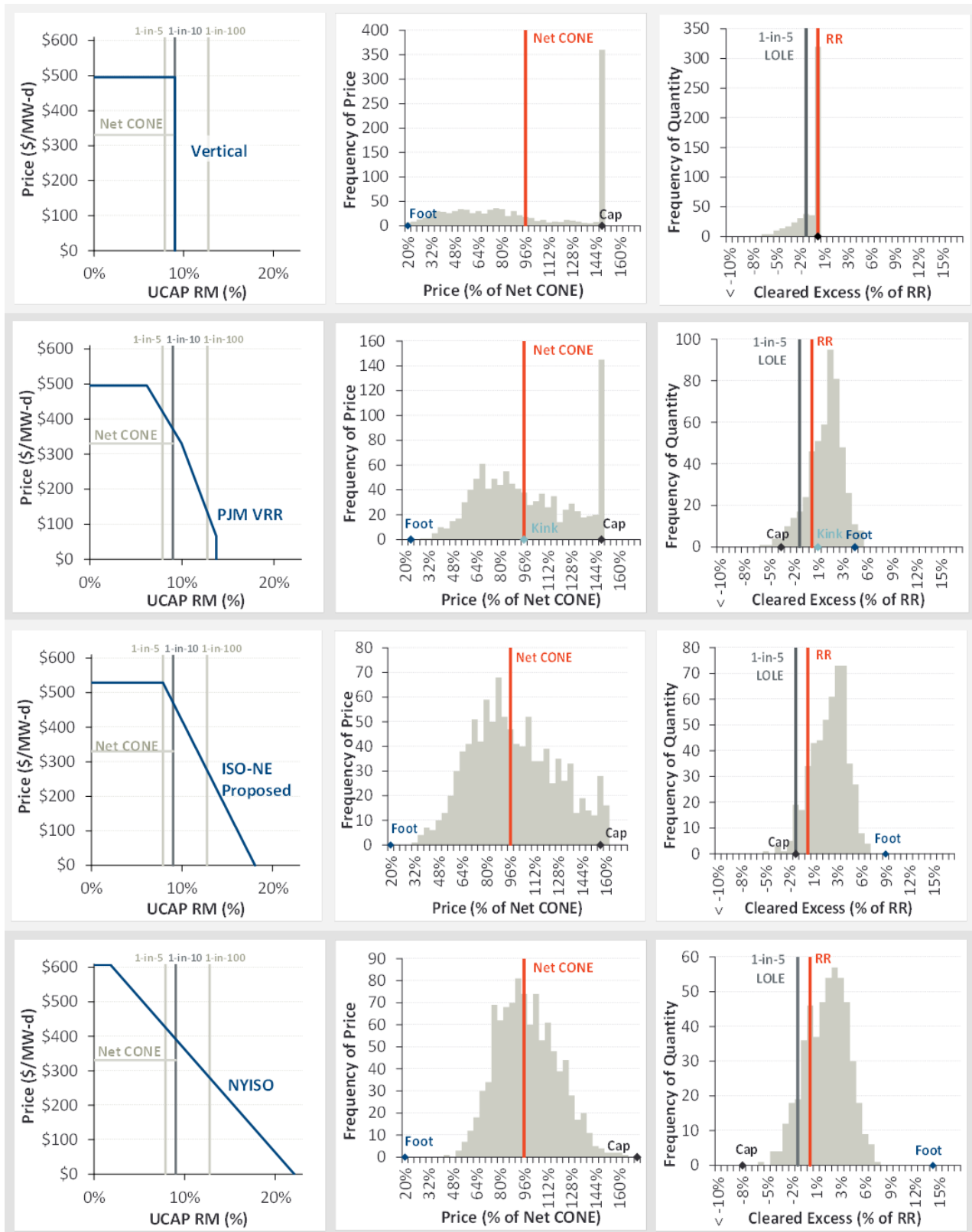
We compare the distribution of price and quantity outcomes under each of these curves as histograms in Figure 10, and present summary statistics comparing these curves in the following Table 8. These distributions show the expected result that the steepest vertical curve has the most price volatility and most quantity certainty, while the flattest NYISO curve shows the most price stability and the widest range of realized quantities.

In each of the three cases, prices are distributed above and below Net CONE, with prices equal to Net CONE on average. This result follows from our assumption that new supply would rationally enter (or not) whenever long-run average prices are above (below) Net CONE. However, the distribution of price outcomes around Net CONE is very different across the curves, with the vertical curve producing volatile bi-modal prices while NYISO's flatter curve produces a relatively stable distribution of prices around Net CONE.

PJM's curve substantially reduces price volatility compared to the vertical curve, with a standard deviations of \$95/MW-d (29% of Net CONE) and \$147/MW-d (44% of Net CONE) respectively. However, the curve does not mitigate price volatility as much as the flatter curve of NYISO, which has a standard deviation of \$69/MW-d (21% of Net CONE).

Figure 20

Simulated Price and Quantity Outcomes with Current VRR Curve and Other Pre-Defined Curves



Sources and Notes:

Price distribution charts summarize the outcomes of our simulation modeling results for each curve over 1,000 draws.

In terms of quantity outcomes, the vertical curve shows the most quantity certainty, while the NYISO curve produces the widest distribution of realized quantities. This distribution of quantity outcomes can be translated into realized reliability levels, by calculating the LOLE from each draw and estimating the average LOLE over many draws. In general, a wider distribution of quantity outcomes (if they are distributed around the same average quantity) will result in lower reliability, because excursions far below the reliability impact have a disproportionately large impact on average reliability.

Averaging these realized reliability outcomes across draws shows that PJM’s current VRR curve does not meet the reliability objectives, with the distribution of quantity outcomes corresponding to an average of 0.121 LOLE over many years, compared to 0.1 LOLE at the 1-in-10-year target. The curve also produces a relatively high 20% frequency of reliability outcomes below 1-in-5, a result consistent with our qualitative finding from Section V.A.3 that the flat shape of the curve in the high-price region introduces greater risks of such shortage events. Assuming Net CONE correctly reflects the net cost of new entry (*i.e.*, is not upward biased), both of these results indicate that some or all of PJM’s curve would need to be shifted rightward or upward in order to achieve the 1-in-10 reliability objective on a long-run average basis.

Table 8
Performance of Proposed Curve and Other Pre-Defined Curves⁵⁶

	Price			Reliability					Procurement Costs		
	Average	Standard	Freq.	Average	Average	Reserve	Freq.	Freq.	Average	Average	Average
		Deviation	at Cap	LOLE	Excess	Margin	Below	Below		of Bottom	of Top
					(Deficit)	St. Dev.	Rel. Req.	1-in-5		20%	20%
	(\$/MW-d)	(\$/MW-d)	(%)	(Ev/Yr)	(IRM + X%)	(% ICAP)	(%)	(%)	(\$mil)	(\$mil)	(\$mil)
Base Modeling Assumptions											
Vertical Curve	\$331	\$147	69%	0.175	-0.8%	1.4%	36%	24%	\$19,980	\$8,030	\$31,531
Current VRR Curve	\$331	\$95	6%	0.121	0.4%	2.0%	35%	20%	\$20,167	\$12,672	\$28,094
ISO-NE Proposed Curve	\$331	\$96	3%	0.039	2.7%	2.1%	10%	3%	\$20,554	\$13,327	\$29,310
NYISO Curve	\$331	\$69	0%	0.065	2.0%	2.4%	20%	9%	\$20,456	\$15,394	\$26,490

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

⁵⁶ We note that this table and all similar tables through the remainder of the report may be affected by a small convergence error in Net CONE. As explained in Section IV above, we adjust the total quantity of “Smart Block” supply in each location until prices equal Net CONE on average, and then re-run our Monte Carlo simulation across 1,000 draws with a fixed Smart Block in each location. The resulting model outputs are therefore subject to some convergence error such that realized prices deviate somewhat from Net CONE, typically by +/- 0.2% of Net CONE. To correct for this error we adjust average price and cost results proportionally, but report this as an indicator of the level of model error that should be assumed.

2. Sensitivity to Primary Modeling Uncertainties

We test the robustness of our conclusions and identify the primary drivers of our results using a sensitivity analysis on our modeling assumptions, as summarized in Table 9. We first test the sensitivity to individual shocks, by eliminating one type of shock at a time and then testing our results if all shocks are 33% larger or 33% smaller, while remaining symmetrically distributed around the same average values. As expected, eliminating or reducing any type of shock will reduce the distribution of price and quantity outcomes and also improve reliability performance. Among the sources of volatility that we examined, our results are most sensitive to supply shocks, followed by the much smaller impacts from shocks to demand and, finally, to non-systematic administrative Net CONE estimation errors.

Comparing higher and lower shocks cases, we note the substantial asymmetry in reliability results. Decreasing shocks by 33% reduces LOLE by 0.032 (from 0.0121 to 0.089) events per year, while increasing shocks by 33% increases LOLE by 0.065 (from 0.121 to 0.186) events per year or twice as much. This asymmetry is caused by the relatively steep shape of the LOLE curve at low reserve margins. The higher shocks 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 under Base and Sensitivity Case Assumptions

	Price			Reliability					Procurement Costs		
	Average (\$/MW-d)	Standard Deviation (\$/MW-d)	Freq. at Cap (%)	Average LOLE (Ev/Yr)	Average Excess (Deficit) (IRM + X%)	Reserve Margin St. Dev. (% ICAP)	Freq. Below Rel. Req. (%)	Freq. Below 1-in-5 (%)	Average (\$mil)	Average of Bottom 20% (\$mil)	Average of Top 20% (\$mil)
Current VRR Curve											
Current VRR Curve	\$331	\$95	6%	0.121	0.4%	2.0%	35%	20%	\$20,167	\$12,672	\$28,094
Zero Out Supply Shocks	\$331	\$50	0%	0.074	0.8%	1.0%	22%	4%	\$20,283	\$16,364	\$24,824
Zero Out Demand Shocks	\$331	\$91	4%	0.115	0.5%	1.9%	35%	19%	\$20,170	\$12,831	\$27,617
Zero Out Net CONE Shocks	\$331	\$93	5%	0.120	0.5%	2.0%	35%	20%	\$20,170	\$12,603	\$27,749
All Shocks 33% Higher	\$331	\$115	12%	0.186	0.2%	2.7%	39%	26%	\$20,087	\$10,923	\$29,638
All Shocks 33% Lower	\$331	\$70	1%	0.089	0.7%	1.4%	29%	11%	\$20,227	\$14,826	\$26,227

Notes:

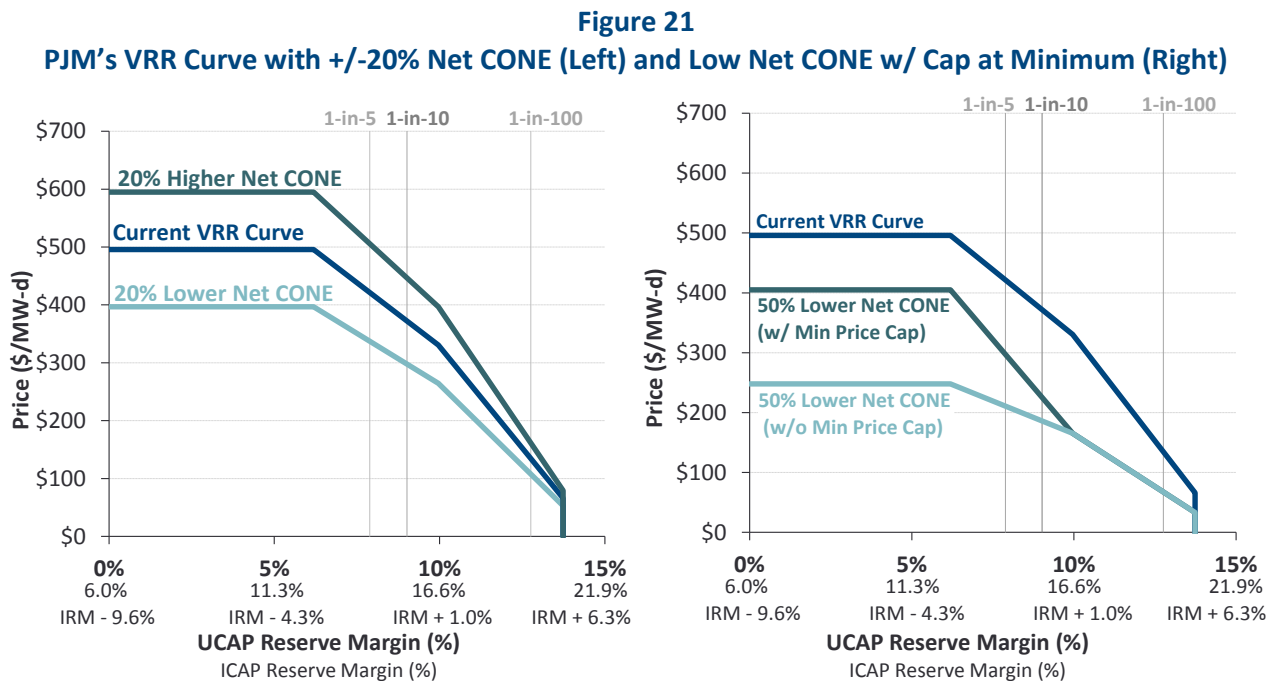
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

3. Performance with Higher or Lower Net CONE

Ideally, a curve should perform well not only under today's system conditions, but also under very different conditions, such as changes in Net CONE. We do anticipate at least some performance robustness to system conditions, because the VRR curve is indexed to Net CONE and will therefore adjust as Net CONE changes over time. If energy prices decrease and the energy market provides a smaller proportion of the incentives necessary to invest, then the administrative Net CONE and VRR

curve will increase even if Gross CONE stays the same. Similarly, when energy prices increase, the demand curve will decrease, providing approximately the same investment incentives overall.

We examine the performance of the VRR curve under +/-20% changes to Net CONE, as well as under a 50% reduction in Net CONE. We test more extreme decreases than increases because the currently low E&AS offset has more upside than downside, and also in order to evaluate the impact of the price cap minimum at Gross CONE.⁵⁷ We illustrate the resulting demand curves under these cases in Figure 26 and present simulation results in Table 7. Note that these sensitivities reflect changes in Net CONE under the assumption of no estimation error; sensitivities to estimation error are presented in the following section.



Sources and Notes:

Current VRR Curve shows the VRR curve as specified in the 2016/17 PJM Planning Parameters, see PJM (2013a.)
 In the 20% Higher Net CONE, 20% Lower Net CONE, and 50% Lower Net CONE (w/o Min Price Cap) curves, points “a”, “b”, and “c” are each 20% higher, 20% lower, and 50% lower than the current VRR curve, respectively.
 The 50% Lower Net CONE (w/Min Price Cap) curve has point “a” set to 2016/17 Gross CONE.

⁵⁷ Specifically, the price at point “a” is calculated as the maximum of 1.5× Net CONE or 1× Gross CONE, so the cap can never fall below Gross CONE. See Manual 18, PJM (2014a), Section 3.4.

We find that the curve performs similarly under modest changes of 20%, with reliability declining by 0.009 events per year under the 20% Net CONE increase or improving by 0.007 events per year in the 20% Net CONE decrease. The intuition behind the improved reliability levels is that at lower Net CONE values, the VRR curve is compressed to a lower price range within which the supply curve is more elastic (less steep). The higher supply elasticity mitigates the reliability effects of supply and demand shocks. We find that the curve performs similarly under modest changes of 20%, with reliability declining by 0.009 events per year under the 20% Net CONE increase or improving by 0.007 events per year in the 20% Net CONE decrease. The intuition behind the improved reliability levels is that reducing Net CONE values compresses the demand curve to a lower price range within which the supply curve is less steep. The higher supply elasticity mitigates the reliability effects of supply and demand shocks.

However, for a much larger 50% decrease in Net CONE, the impact on reliability depends on whether the price cap minimum at Gross CONE is observed. Without the price cap minimum, reliability degrades to LOLE of 0.150 events per year, with the increased low-reliability events primarily related to administrative error in Net CONE. At these low levels with the entire VRR curve shifted down, administrative uncertainty is a greater as a percentage of Net CONE due to the higher proportion of E&AS offset as a fraction of Gross CONE. This makes it more likely that the auction will clear in the low and very low reserve margin region.

Observing the price cap minimum at $1 \times$ Gross CONE protects against this outcome, with reliability that is improved beyond target levels at LOLE of 0.076 events per year. The price cap minimum also protects against any downward bias in Net CONE estimation, which could conceivably be a much larger fraction of Net CONE at high E&AS offset levels corresponding to a lower Net CONE. Such under-estimates could precipitously compromise reliability, as discussed further in the following Section.

Table 10
Performance of VRR Curve with Higher and Lower Net CONE

	Price			Reliability					Procurement Costs		
	Average (\$/MW-d)	Standard Deviation (\$/MW-d)	Freq. at Cap (%)	Average LOLE (Ev/Yr)	Average Excess (Deficit) (IRM + X%)	Reserve Margin St. Dev. (% ICAP)	Freq. Below Rel. Req. (%)	Freq. Below 1-in-5 (%)	Average (\$mil)	Average of Bottom 20% (\$mil)	Average of Top 20% (\$mil)
With Price Cap Minimum at Gross CONE											
20% Higher Net CONE	\$397	\$120	7%	0.130	0.4%	2.2%	37%	22%	\$24,180	\$14,831	\$34,187
Base Case	\$331	\$95	6%	0.121	0.4%	2.0%	35%	20%	\$20,167	\$12,672	\$28,094
20% Lower Net CONE	\$264	\$73	5%	0.114	0.5%	2.0%	33%	17%	\$16,144	\$10,285	\$22,189
50% Lower Net CONE	\$165	\$57	0%	0.076	1.0%	1.6%	25%	7%	\$10,141	\$5,888	\$15,298
Without Price Cap Minimum at Gross CONE											
50% Lower Net CONE	\$165	\$50	7%	0.150	0.1%	2.5%	39%	22%	\$10,074	\$6,205	\$14,610

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

4. Sensitivity to Administrative Errors in Net CONE

In the analyses presented up to this point, we assume that the administrative Net CONE estimate accurately represents the true Net CONE that developers need to earn in order to enter. However, estimation error is inevitable even in a careful analysis due to uncertainties in every component of Net CONE estimate, for example in: (a) the identification of an appropriate reference technology; (b) estimation of the capital and fixed operation and maintenance (FOM) costs; (c) translation of those costs into an appropriately leveled value consistent with developers' cost of capital, long-term views about the market, and assumed economic life; and (d) estimation of E&AS margins.

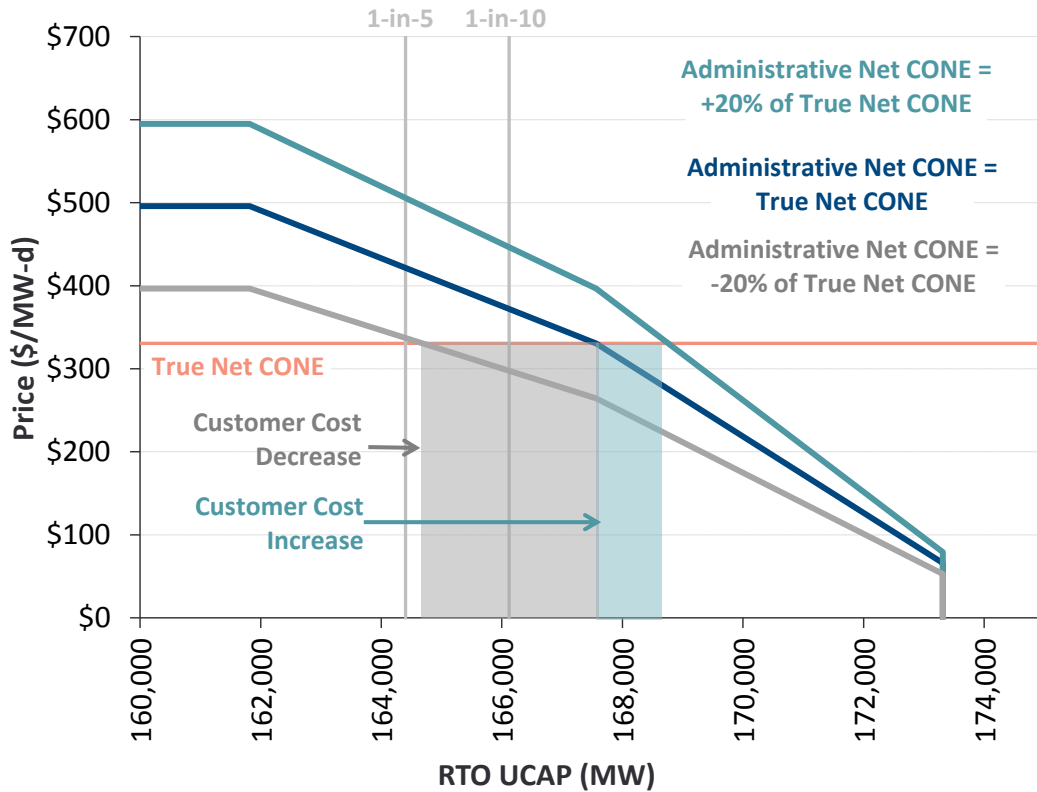
If the administrative estimate of Net CONE understates true Net CONE, the demand curve would be lower than needed to meet the reliability objectives, as shown in an example in Figure 22. Supply would still enter and set prices at the true Net CONE in the long term, but the cleared quantity and reliability would be below target.⁵⁸ Conversely, overstated Net CONE would attract excess supply as suppliers continued entering until average prices equal the true Net CONE. Customers would not have to pay higher prices in the long term, but they would have to buy a greater quantity that has diminishing value.

We test the robustness of the VRR curve's performance to administrative Net CONE estimation errors of +/-20%, as summarized in Table 11. In both cases, we hold true Net CONE at the base value of \$331/MW-d, always adjusting supply until the long-term average price across simulation draws equals to that value no matter what the demand curve, as shown in Figure 22.⁵⁹

⁵⁸ In the short term (*i.e.*, in any one year) an over-estimate or under-estimate in Net CONE would increase or decrease prices respectively, since in a particular auction the demand curve is cleared against a relatively fixed short-term supply curve with the majority of the resource base not making entry or exit decisions in any one auction. The point we make here is that prices will not stay persistently above or below Net CONE in the long term, because this *would* result enough resources entering or exiting to move long-term average prices back to true Net CONE.

⁵⁹ We specify the sensitivities by fixing true Net CONE rather than fixing administrative Net CONE so that cost outcomes would be comparable.

Figure 22
VRR Curve Performance with 20% Over- or Under-Estimate in Net CONE
 Assuming True Net CONE Equals the Base Case Value of \$331/MW-d



Sources and Notes:

The curve with Administrative Net CONE = True Net CONE shows the VRR curve as specified in the 2016/17 PJM Planning Parameters. In the other two curves, points “a”, “b”, and “c” are each 20% higher or 20% lower than the base curve. In call cases, however, True Net CONE is equal to the 2016/17 Net CONE from the PJM Planning Parameters. See PJM (2013a.)

The most important observation from these tests is that Net CONE estimation errors can have a substantial impact on reliability outcomes. Reliability impacts of estimation errors are asymmetric with respect to positive and negative estimation errors because shortage frequencies rise increasingly steeply as reserve margins fall below target (see the shape of the LOLE curve in Section IV.B.3 above). A 20% underestimate worsens LOLE by 0.249 (to 0.370 events/yr), whereas an overestimate improves it by only 0.057 (to 0.064 events/yr).

In both cases, impacts on long-term average customer capacity procurement costs are small because average market clearing prices depend on suppliers’ true Net CONE, not on administrative estimates or errors thereof. Capacity procurement costs change only because cleared quantities change, causing customers to buy a little more or less capacity. We show these customer cost increases or decreases schematically in as the blue and gray squares, respectively in Figure 22. For example, if true Net CONE is \$331/MW-d, overestimating Net CONE by 20% would increase capacity procurement costs by \$185 million per year, or only 0.9% of total capacity procurement costs; underestimating Net CONE by 20% would reduce costs by a larger \$350 million per year, or about

1.7%.⁶⁰ Note that these capacity procurement cost impacts do not account for all of the energy costs or reliability-related costs that would change as reserve margins change, such as those we have described in a recent analysis conducted for FERC.⁶¹

Table 11
Performance of Current VRR Curve with Administrative Error in Net CONE

	Price			Reliability					Procurement Costs		
	Average	Standard	Freq.	Average	Average	Reserve	Freq.	Freq.	Average	Average	Average
	(\$/MW-d)	Deviation	at Cap	LOLE	Excess	Margin	Below	Below		of Bottom	of Top
		(\$/MW-d)	(%)	(Ev/Yr)	(Deficit)	St. Dev.	Rel. Req.	1-in-5	(\$mil)	(\$mil)	(\$mil)
					(% ICAP)	(%)	(%)	(%)		20%	20%
Base Case											
Accurate Net CONE	\$331	\$95	6%	0.121	0.4%	2.0%	35%	20%	\$20,167	\$12,672	\$28,094
20% Over-Estimate	\$331	\$114	1%	0.064	1.5%	1.8%	18%	8%	\$20,352	\$11,568	\$30,579
20% Under-Estimate	\$331	\$64	26%	0.370	-1.7%	2.5%	69%	50%	\$19,817	\$14,757	\$24,543

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

These observations point to three key insights important for reducing vulnerability to low reliability outcomes. The first and most obvious insight is that the administratively-determined Net CONE must be estimated as accurately as possible for the demand curve to achieve its resource adequacy objectives. It is particularly important to avoid underestimating Net CONE, to avoid the asymmetrically high reliability risks.

The second insight is that applying a minimum of 1× Gross CONE to the price cap substantially reduces the risk of under-procuring when high E&AS revenues and low Net CONE would otherwise collapse the demand curve. However, the fact that the VRR curve kink at point “b” continues to drop even if the cap is at its minimum quantity, helps to prevent over-procurement under those conditions.

The third insight is that most of the reliability risks derive from the flatness of the top part of the demand curve, combined with the moderate price cap at only 1.5× Net CONE. This flat portion of the curve and the moderate price cap help to substantially mitigate price volatility and market power concerns, but at the tradeoff of introducing substantial reliability risks in the event of a under-

⁶⁰ Understating Net CONE decreases customer capacity costs more than overstating Net CONE increases them because the cleared quantities are asymmetrically lower due to the kink in the curve at the cap. The price stops increasing once it reaches the cap, so the distribution of outcomes must shift leftward to achieve a greater frequency of low-quantity price cap events and maintain average prices at true Net CONE. The relative proportion in cost increases or decreases is shown as the area in the blue or gray boxes in Figure 22 respectively.

⁶¹ See Pfeifenberger (2013).

estimate of Net CONE. Making the curve steeper in this region or increasing the cap would substantially reduce these risks, but would also increase price volatility.

C. OPTIONS FOR IMPROVING THE VRR CURVE'S PERFORMANCE

The prior two Sections describe reliability risks under the existing VRR curve. Namely, we find that the VRR curve would not achieve the target LOLE of 0.1 on average under Base Case assumptions, and performance would deteriorate substantially further if Net CONE were systematically underestimated. In this Section, we evaluate three approaches to improving reliability outcomes:

1. Adjusting the price and quantity at point “a” (the price cap point) to sharpen price signals when reserve margins decline;
2. Adjusting the shape of the curve in various other ways; and
3. Right-shifting the entire curve to avoid low reliability outcomes by procuring more on average and protecting against supply-demand shocks and Net CONE estimation error.

Each approach can improve reliability outcomes but may have tradeoffs regarding price volatility or over-procurement. We estimate here the impact of each potential change on reliability, price, and cost criteria under base case and stress scenarios.

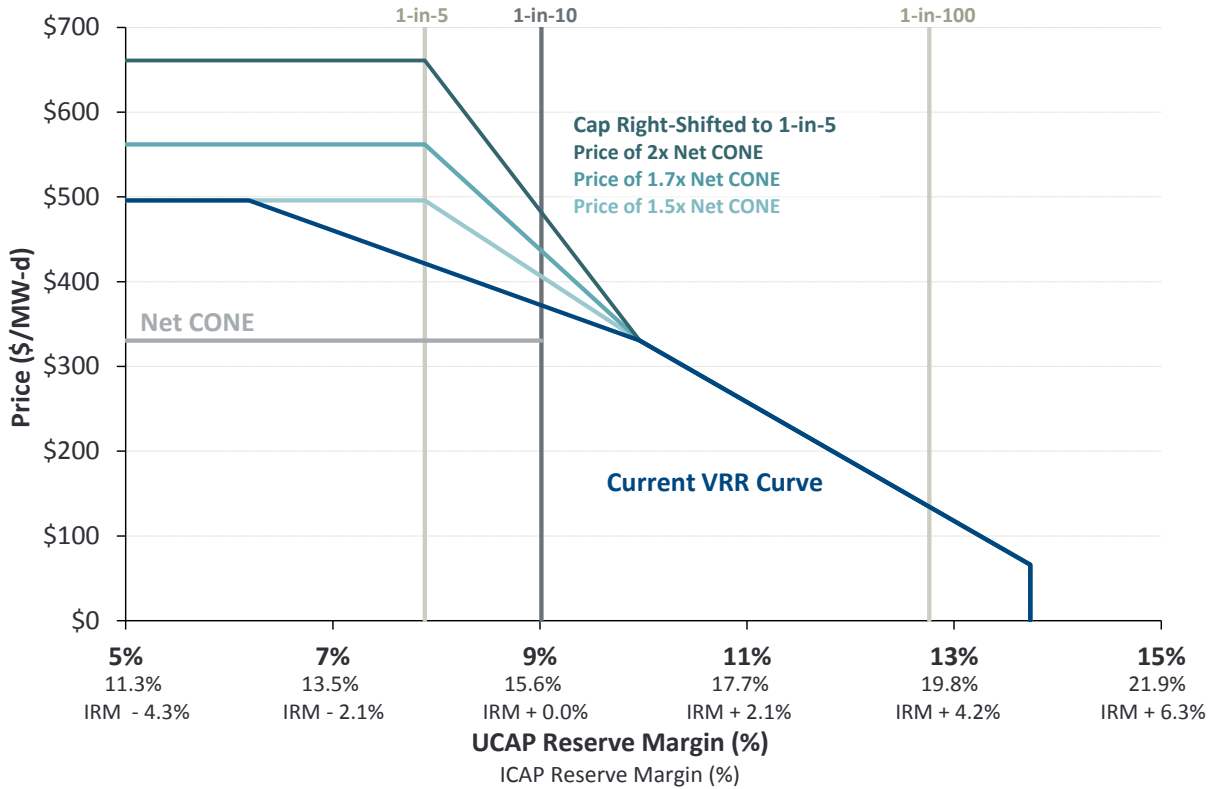
1. Adjusting the Cap at Point “a” to Reduce Low-Reliability Events

The existing VRR curve has a price cap of $1.5 \times$ Net CONE (with a minimum value of $1.0 \times$ CONE), at a quantity equal to IRM-3%.⁶² As discussed in Sections V.A.2 and V.A.3, this makes the upper section of the curve less steep than the lower section, so price signals increase at a relatively low rate as reserve margins fall into the very low reliability region. Increasing prices in the low-reliability section of the curve would produce stronger price signals during shortage conditions and result in procuring additional resources when they are most needed for reliability. Increasing the price cap would also protect against systematic under-procurement if Net CONE were underestimated.

We test two types of adjustments to the VRR curve's price cap point “a”: (1) right-shifting point “a” to a quantity corresponding to a 1-in-5 LOLE, or IRM-1.2%; and (2) right-shift point “a” and then also increasing the cap price from $1.5 \times$ Net CONE to $1.7 \times$ or $2 \times$ Net CONE. These alternatives are depicted in Figure 23.

⁶² See PJM (2013a.)

Figure 23
PJM's Current VRR Curve after Right-Shifting and Increasing the Price Cap



Sources and Notes:

Current VRR Curve reflects the system VRR curve in the 2016/2017 PJM Planning Parameters, see PJM (2013a).

Simulation analyses of these alternative candidate curves show that modest changes substantially reduce the frequency of low reliability events, as summarized in Table 12. Under Base assumptions, right-shifting the cap reduces the frequency of low reserve margins (*i.e.*, below the level corresponding to 1-in-5 LOLE) from 20% to 12%; then raising the cap price reduces that frequency further to 9% with a 1.7× cap and 7% with a 2.0× cap. The improvement is even greater under the scenario in which administrative Net CONE is 20% below true Net CONE. However, increasing the cap increases overall price volatility, as shown by the standard deviation of simulated prices.

Table 12
Performance of VRR Curve if Right-Shifting and Increasing the Price Cap at Point “a”

	Price			Reliability					Procurement Costs		
	Average	Standard	Freq.	Average	Average	Reserve	Freq.	Freq.	Average	Average	Average
		Deviation	at Cap	LOLE	Excess	Margin	Below	Below		of Bottom	of Top
	(\$/MW-d)	(\$/MW-d)	(%)	(Ev/Yr)	(Deficit)	St. Dev.	Rel. Req.	1-in-5	(\$mil)	20%	20%
					(IRM + X%)	(% ICAP)	(%)	(%)		(\$mil)	(\$mil)
Base Modeling Assumptions											
Current Curve	\$331	\$95	6%	0.121	0.4%	2.0%	35%	20%	\$20,167	\$12,672	\$28,094
Cap at 1-in-5, 1.5x	\$331	\$107	12%	0.096	0.8%	1.9%	28%	12%	\$20,224	\$12,071	\$29,579
Cap at 1-in-5, 1.7x	\$331	\$124	9%	0.079	1.1%	1.7%	23%	9%	\$20,267	\$11,438	\$32,019
Cap at 1-in-5, 2x	\$331	\$145	7%	0.065	1.3%	1.6%	18%	7%	\$20,305	\$10,863	\$35,033
20% Under-Estimated Net CONE											
Current Curve	\$331	\$64	26%	0.370	-1.7%	2.5%	69%	50%	\$19,817	\$14,757	\$24,543
Cap at 1-in-5, 1.5x	\$331	\$73	38%	0.272	-1.0%	2.4%	57%	38%	\$19,928	\$13,784	\$25,250
Cap at 1-in-5, 1.7x	\$331	\$97	25%	0.166	-0.2%	2.0%	45%	25%	\$20,053	\$12,449	\$27,912
Cap at 1-in-5, 2x	\$331	\$124	14%	0.112	0.3%	1.8%	33%	14%	\$20,145	\$11,323	\$31,341

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

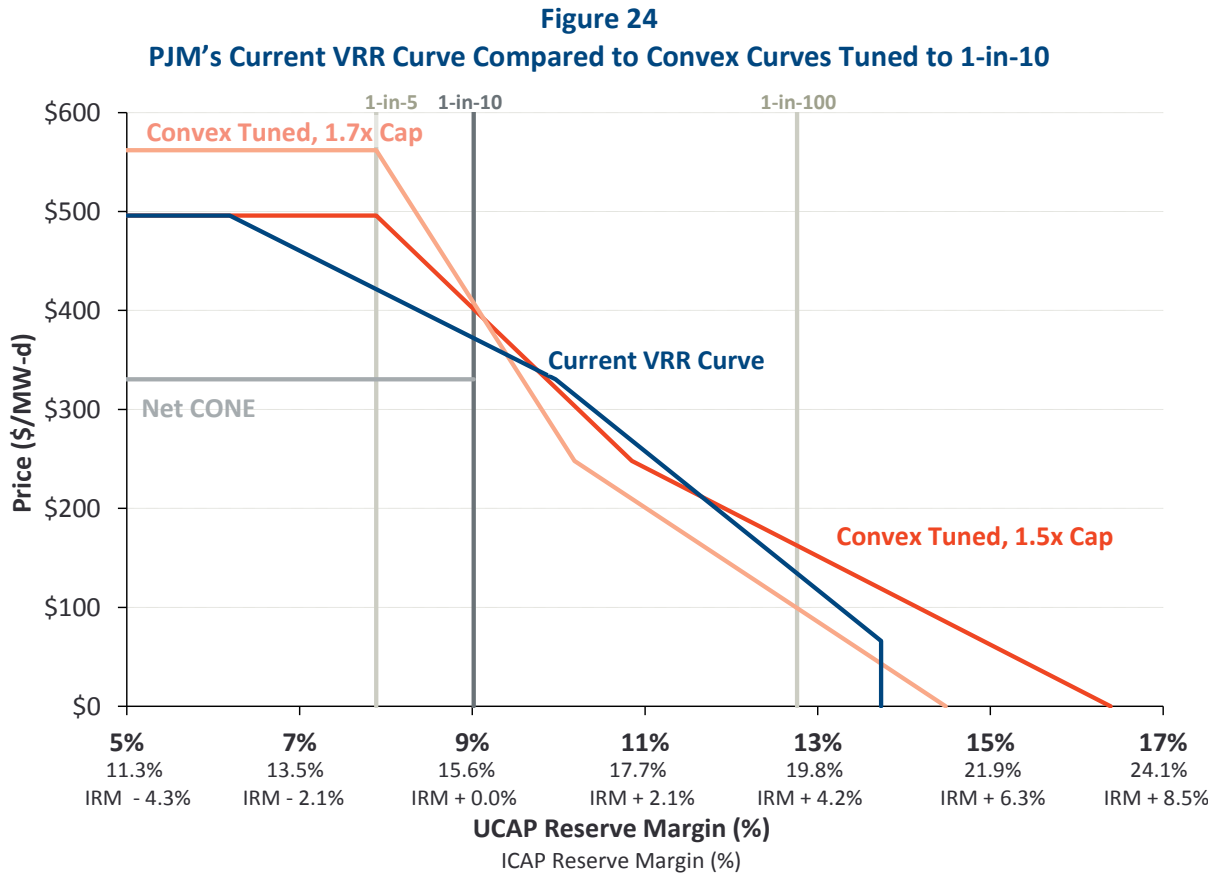
Right-shifting point “a” helps reliability not only by procuring more in the auctions when incremental supply is most needed (*i.e.*, when supply-demand shocks are greatest), but also by increasing the procured quantity on an average basis across all simulation draws. The fact that average reserve margins increase by 0.4% under Base assumptions and 0.7% if Net CONE is underestimated suggests that the improved reliability derives partly from adding money to the market, inducing entry, and shifting the whole distribution of outcomes to the right. This observation can be explained as follows: because the supply curves in our simulations are not very elastic at high prices, increasing the price cap causes prices to rise more than cleared quantities during short-supply years. However, supply is more elastic in the long-term. The prospect of reaching the price cap more quickly if supplies tighten (even if rarely) supports increased entry. This explains why right-shifting and increasing the cap results in such substantial reliability improvements, including improving reliability somewhat beyond the 1-in-10 objective.

By contrast, moving the lower part of the demand curve up or to the right would interact with a lower part of the supply curve where price elasticity is greater, leading to a larger change in cleared quantities and smaller change in prices in any particular auction when supply-demand shocks are in the surplus direction. Unfortunately, increasing cleared quantities in outcomes where reserve margins were already quite high adds little to average reliability. Nevertheless, in the following two sections, we evaluate shifting other parts of the curve to avoid the price volatility implications of only raising or right-shifting the cap.

2. Options for Steeper and Flatter Convex VRR Curves Tuned to 1-in-10

Adjusting point “a” as described above improves reliability performance by allowing prices to rise more steeply when reserve margins are low. However, if the cap is not increased above the current 1.5× Net CONE, the curve would be nearly a straight line. As discussed in Section V.A.2, a more convex curve shape has several theoretical advantages, by providing stronger price signals as the system approaches short supply conditions and more nearly reflecting the relationship between LOLE and reserve margin.

To evaluate the performance of a reshaped convex VRR curve, we tested two alternative curves: (1) a convex curve with a price cap at 1.5× Net CONE; and (2) a convex curve with a price cap at 1.7× Net CONE. Both curves set the point “a” quantity at the cap at the same 1-in-5 point as described in the prior section, with the other curve parameters adjusted until the simulated average LOLE meets the objective of 0.1 events per year. These two, convex tuned curves are depicted in Figure 24.



Sources and Notes:

Current VRR Curve reflects the system VRR curve in the 2016/2017 PJM Planning Parameters. See PJM (2013a.)

Our simulation analysis shows that both curves provide substantially better reliability than the current VRR curve as shown in Table 13. However, the curve with a 1.5× cap appears better overall because it has substantially lower price volatility and the flatter shape would provide better protection against potential exercise of market power. The convex 1.7× curve shows better

performance in terms of both frequency at the cap and frequency below 1-in-5 but this improvement is relatively small compared to the substantially greater price volatility.

Comparing Table 13 to Table 12 shows that the performance of the Convex Tuned 1.5x Cap curve is very similar in all respects to that of the curve in which only point “a” is right-shifted to 1-in-5. This is because the two curves are very similar everywhere except the right-most sections, where the convex curve is higher and flatter. Even though the convex curve does not exhibit substantial performance differences in our simulations, we believe it would marginally improve RPM. It sets prices more nearly proportionally to marginal reliability value, and would reduce price volatility and susceptibility to market power abuse in the flatter half of the curve. Finally, it avoids the anomalous “cliff” that the current VRR curve has at point “c.”

Table 13
Performance of Current VRR Curve Compared to Convex Curves Tuned to 1-in-10

	Price			Reliability					Procurement Costs		
	Average	Standard Deviation	Freq. at Cap	Average LOLE	Average Excess (Deficit) (IRM + X%)	Reserve Margin St. Dev. (% ICAP)	Freq. Below Rel. Req. (%)	Freq. Below 1-in-5 (%)	Average of Bottom 20% (\$mil)	Average of Top 20% (\$mil)	Average of Top 20% (\$mil)
	(\$/MW-d)	(\$/MW-d)	(%)	(Ev/Yr)	(IRM + X%)	(% ICAP)	(%)	(%)	(\$mil)	(\$mil)	(\$mil)
Base Modeling Assumptions											
Current VRR Curve	\$331	\$95	6%	0.121	0.4%	2.0%	35%	20%	\$20,167	\$12,672	\$28,094
Convex Tuned, 1.5x Cap	\$331	\$107	13%	0.100	0.7%	1.9%	29%	13%	\$20,210	\$12,379	\$29,631
Convex Tuned, 1.7x Cap	\$331	\$134	12%	0.100	0.5%	1.7%	29%	12%	\$20,171	\$10,987	\$32,648

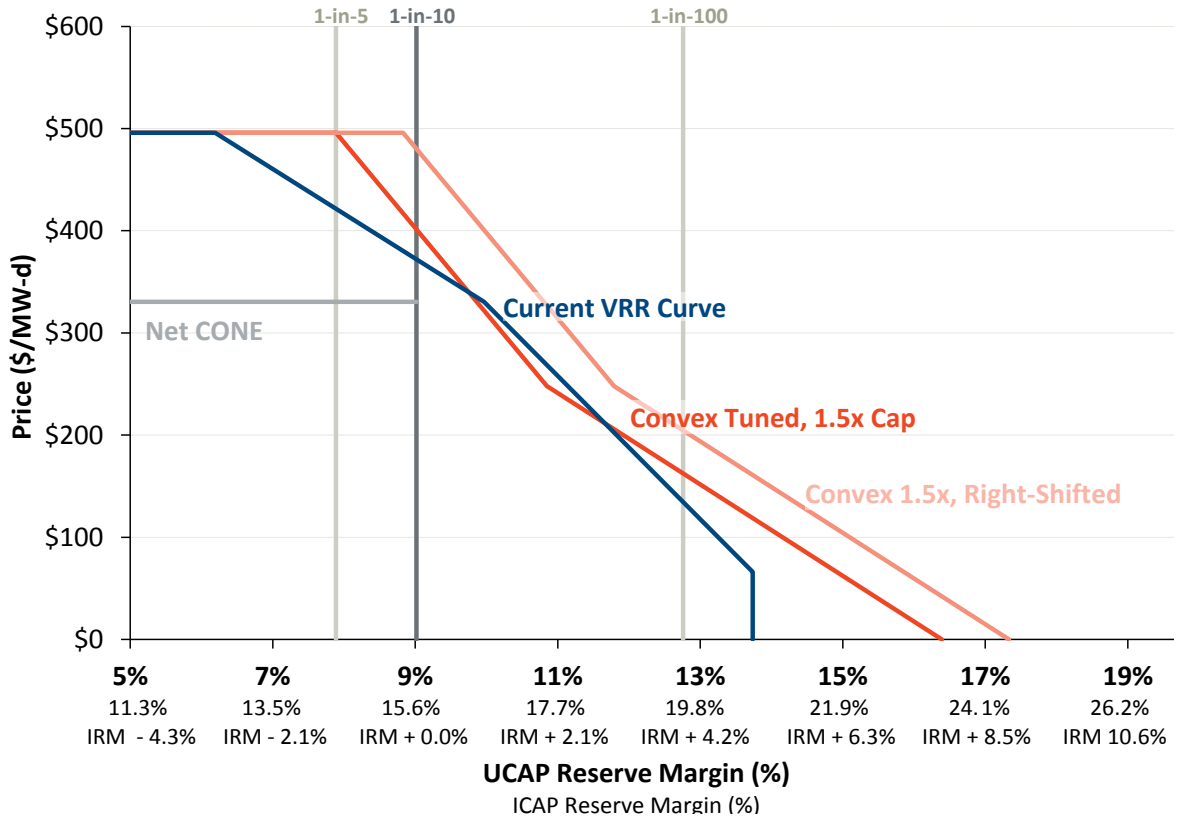
Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

3. Option for a Right-Shifted Curve to Mitigate Low-Reliability Events

Although the convex curve presented above performs better than the current VRR curve, it still produces reserve margins below the 1-in-5 level (at about IRM-1%) approximately 13% of the time under Base modeling assumptions. The curve could also under-procure capacity if either shocks or Net CONE are underestimated, as shown in Table 15 in the following section. Therefore, we also evaluate the option shifting the entire curve to the right as a sort of insurance against these risks. We test the performance impacts of this change by right-shifting each point on the 1.5x convex curve by 1% IRM, as shown in Figure 25.

Figure 25
PJM's Current VRR Curve Compared to Alternative VRR Curve Shapes



Sources and Notes:

Current VRR Curve reflects the system VRR curve in the 2016/17 PJM Planning Parameters. See PJM (2013a).

Our simulations show that the right-shifted curve improves reliability, with reserve margins falling below the Reliability Requirement only 16% of the time and below the 1-in-5 level only 7% of the time. The improvement is even greater under the stress scenarios shown in the next section. However, this increased security comes at a slight cost, with procurement costs slightly less than 1% higher corresponding to the 1% higher average reserve margin.

Table 14
Performance of Current VRR Curve, Convex Curve, and Right-Shifted Convex Curve

	Price			Reliability					Procurement Costs		
	Average	Standard Deviation	Freq. at Cap	Average LOLE	Average Excess (Deficit)	Reserve Margin St. Dev.	Freq. Below Rel. Req.	Freq. Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	(\$/MW-d)	(\$/MW-d)	(%)	(Ev/Yr)	(IRM + X%)	(% ICAP)	(%)	(%)	(\$mil)	(\$mil)	(\$mil)
Base Modeling Assumptions											
Current VRR Curve	\$331	\$95	6%	0.121	0.4%	2.0%	35%	20%	\$20,167	\$12,672	\$28,094
Convex Tuned, 1.5x Cap	\$331	\$107	13%	0.100	0.7%	1.9%	29%	13%	\$20,210	\$12,379	\$29,631
Convex 1.5x, Right-Shifted	\$331	\$107	13%	0.060	1.7%	1.9%	16%	7%	\$20,383	\$12,461	\$29,859

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

4. Sensitivity of Alternative Curves' Performance

In addition to testing the performance of the current VRR curve to alternative curves under Base modeling assumptions, we also compare the robustness of each curve under alternative assumptions as summarized in Table 15. All of the alternative curves improve reliability performance under our Base modeling assumptions. Under stress scenarios with greater supply-demand shocks and Net CONE underestimation, the improvement is even greater. As we have explained earlier, the current VRR curve is susceptible to rapid deterioration from a reliability perspective, especially in the case of under-estimated Net CONE, because of the moderate price cap and relatively flat shape in the low-reliability region of the curve.

We observe that the convex-shaped curves appear much more robust from a reliability perspective than the current concave shape. The higher price cap in the 1.7× cap curve provides the most protection against reliability degradation under stress scenarios, with the higher cap protecting against low-reliability events of all types but particularly against under-estimates of Net CONE. The steeper shape of this curve also reduces the magnitude of over-procurement caused by over-estimating Net CONE compared to the other curves. However, as we have discussed previously the 1.7× cap curve has greater price volatility and provide less protection against exercise of market power. The right-shifted curve shows the best reliability performance across all scenarios, related to the higher average procurement quantities across all scenarios. This protection against plausible stress scenarios would increase capacity procurement costs by approximately 1.0%-1.4% depending on the scenario.

Considering each of these factors, we recommend that PJM and stakeholders consider adopting the 1.5× convex curve for use in RPM. Adopting this curve would substantially reduce the likelihood of low-reliability events, achieve the 1-in-10 objective in expectation, and provide better performance under stress scenarios. Adopting this curve would come at the expense of a modest increase in price volatility and an approximately 0.2% increase in capacity procurement costs.

While the 1.7× cap curve and right-shifted 1.5× curve provide superior protection against low reliability scenarios and generally good performance in other dimensions, we do not adopt either of these options as our primary recommendation because of the greater price volatility (in the former case) and somewhat higher procurement costs (in the latter case). However, we do recommend that options, such as increasing the price cap or refining the curve shape, be considered as options in future triennial VRR curve reviews and CONE studies to ensure that the curve can be adjusted for major challenges as they arise.

Table 15
Performance of VRR Curve and Alternative Curves under Sensitivity Assumptions

	Price			Reliability					Procurement Costs		
	Average	Standard Deviation	Freq. at Cap	Average LOLE	Average Excess (Deficit)	Reserve Margin St. Dev. (% ICAP)	Freq. Below Rel. Req. (%)	Freq. Below 1-in-5 (%)	Average	Average of Bottom 20%	Average of Top 20%
	(\$/MW-d)	(\$/MW-d)	(%)	(Ev/Yr)	(IRM + X%)	(% ICAP)	(%)	(%)	(\$mil)	(\$mil)	(\$mil)
Base Modeling Assumptions											
Current VRR Curve	\$331	\$95	6%	0.121	0.4%	2.0%	35%	20%	\$20,167	\$12,672	\$28,094
Convex Tuned, 1.5x Cap	\$331	\$107	13%	0.100	0.7%	1.9%	29%	13%	\$20,210	\$12,379	\$29,631
Convex Tuned, 1.7x Cap	\$331	\$134	12%	0.100	0.5%	1.7%	29%	12%	\$20,171	\$10,987	\$32,648
Convex 1.5x, Right-Shifted	\$331	\$107	13%	0.060	1.7%	1.9%	16%	7%	\$20,383	\$12,461	\$29,859
20% Under-Estimate in Net CONE											
Current VRR Curve	\$331	\$64	26%	0.370	-1.7%	2.5%	69%	50%	\$19,817	\$14,757	\$24,543
Convex Tuned, 1.5x Cap	\$331	\$73	39%	0.282	-1.1%	2.4%	59%	39%	\$19,912	\$13,628	\$25,267
Convex Tuned, 1.7x Cap	\$331	\$103	28%	0.194	-0.6%	2.0%	50%	28%	\$19,984	\$11,702	\$28,071
Convex 1.5x, Right-Shifted	\$331	\$74	39%	0.182	-0.1%	2.4%	42%	28%	\$20,086	\$13,742	\$25,489
20% Over-Estimate in Net CONE											
Current VRR Curve	\$331	\$114	1%	0.064	1.5%	1.8%	18%	8%	\$20,352	\$11,568	\$30,579
Convex Tuned, 1.5x Cap	\$331	\$123	5%	0.056	1.7%	1.8%	15%	5%	\$20,377	\$11,956	\$32,451
Convex Tuned, 1.7x Cap	\$331	\$151	7%	0.066	1.2%	1.5%	17%	7%	\$20,288	\$10,614	\$35,714
Convex 1.5x, Right-Shifted	\$331	\$123	5%	0.033	2.7%	1.8%	7%	2%	\$20,552	\$12,049	\$32,794
33% Higher Shocks											
Current VRR Curve	\$331	\$115	12%	0.186	0.2%	2.7%	39%	26%	\$20,087	\$10,923	\$29,638
Convex Tuned, 1.5x Cap	\$331	\$124	21%	0.156	0.5%	2.7%	34%	21%	\$20,134	\$10,928	\$30,885
Convex Tuned, 1.7x Cap	\$331	\$155	19%	0.141	0.3%	2.3%	33%	19%	\$20,106	\$9,330	\$33,974
Convex 1.5x, Right-Shifted	\$331	\$124	21%	0.099	1.5%	2.7%	23%	14%	\$20,310	\$11,011	\$31,162
33% Lower Shocks											
Current VRR Curve	\$331	\$70	1%	0.089	0.7%	1.4%	29%	11%	\$20,227	\$14,826	\$26,227
Convex Tuned, 1.5x Cap	\$331	\$84	5%	0.075	0.8%	1.3%	23%	5%	\$20,256	\$14,147	\$28,064
Convex Tuned, 1.7x Cap	\$331	\$105	5%	0.080	0.6%	1.0%	24%	5%	\$20,215	\$12,945	\$30,406
Convex 1.5x, Right-Shifted	\$331	\$84	5%	0.043	1.8%	1.3%	6%	2%	\$20,430	\$14,249	\$28,338

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

D. RECOMMENDATIONS FOR SYSTEM-WIDE CURVE

We find that the existing VRR curve would not satisfy PJM’s primary system-wide reliability objectives on a long-term average basis. For example, we estimate that the average LOLE across all years would be 0.12 (*i.e.*, 0.12 events per year or 1.2 events in 10 years) at the system level, with reliability falling below 1-in-5 LOLE in 20% of all years. These results vary across a range of modeling assumptions, RPM parameter values, and economic shocks that might reasonably be encountered, with objectives being met in some scenarios but widely missed in others. These findings differ from RPM market experience to date because we model long-term equilibrium conditions under which existing surplus resources and low-cost sources of new capacity are exhausted.

To improve RPM performance, we recommend the following VRR Curve revisions. We estimate that adopting these recommendations would result in meeting the 1-in-10 LOLE objective on average, and would reduce the frequency of years below 1-in-5 LOLE to 13% under base modeling assumptions, while also significantly improving VRR curve performance under stress scenarios. The combined effect of these changes is reflected in our recommended convex curve in Figure 24 in Section V.C.2 above. Our specific recommendations are:

- 1. Right-shift point “a”.** We recommend that PJM right-shift point “a” (the highest-quantity point at the price cap) to a quantity at 1-in-5 LOLE (at approximately IRM-1%). This change would significantly improve reliability outcomes by providing stronger price signals when supplies become scarce, without right-shifting the entire distribution of expected reserve margins. Right-shifting point “a” would also make the VRR curve more consistent with PJM’s current reliability backstop auction trigger at IRM-1%, such that PJM would procure all available resources through the BRA before any such backstop auction could be triggered.
- 2. Stretch the VRR Curve into a convex shape.** We recommend that PJM consider adopting the convex shape (*i.e.*, less steep at higher reserve margins) as illustrated in Figure ES-1, with its parameters tuned such that the curve will meet the 1-in-10 reliability standard on average under our base modeling assumptions. This convex shape is more consistent with a gradual decline of reliability at higher reserve margins and helps to reduce price volatility under such market conditions.

VI. Locational Variable Resource Requirement Curves

Reliability challenges at the local level are greater than at the system level. The LDAs are qualitatively different from the system in some ways. For example, their reliability also depends on transmission import limits defined by CETL, which tend to fluctuate and introduce additional volatility in prices and quantities. Moreover, LDAs are small relative to realistic fluctuations in supply, demand, and CETL. In the smallest LDA DPL-South, a 700 MW plant is more than three times the width of the VRR curve (from point “a” to point “c”). And highly import-dependent LDAs are most sensitive to CETL shocks. For example, in PepCo, CETL would represent more than 76% of the Reliability Requirement if the LDA were import-constrained, using 2016/17 parameters. A 12% reduction in CETL (one standard deviation) would correspond to an 822 MW drop in total supply, or more than 130% of the width of the entire VRR curve.

The large size of shocks relative to the VRR curve width causes greater upside volatility in prices, although downside and total price volatility are mitigated on the downside by the “soft floor” on prices created by parent LDAs. If ignoring this multi-area effect, one generating unit or CETL shock could move from the top to the bottom of the curve, eliminating any price premium from the parent area. Indeed, CETL changes have historically driven much of the price volatility in LDAs, where prices have been more price spikes than at the system level.⁶³

The large relative size of shocks also makes LDAs vulnerable to low reliability outcomes. Shock-driven distributions are very wide as a percentage of local Reliability Requirements, and the low reserve margin part of the distributions bring the average conditional LOLE below target.

Further threatening resource adequacy, the likelihood of Net CONE estimation error is higher in small LDAs, and the reliability impacts are greater than at the system level. Estimation error is more likely due to idiosyncratic siting and environmental factors, which may not be discovered in CONE studies due to sparse data on actual projects’ costs (and if the LDA is not its own CONE area), and because E&AS margins are harder to calibrate if there are few comparable plants. Developers may avoid building efficient-scale plants to prevent collapsing the price premium for many years. Simulations show that underestimation degrades reliability, particularly in LDAs.

A. 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

⁶³ See 2011 RPM Review, Table 2 Summary of Major BRA Price Shifts and Causes, Pfeifenberger, *et al.* (2011), p. 15.

the design objectives at the local level; (2) discuss the definition of the locational Reliability Requirement at a 1-in-25 conditional LOLE; (3) review reliability at the price cap, both before and after right-shifting the cap point, as recommended for the system in Section V.C.1 above; (4) compare the width of the curves to anticipated shocks to supply and demand; and (5) evaluate a locational clearing approach with prices more gradually separating at the local level in proportion to reliability value.

1. Locational Design Evaluation Criteria

Locational VRR curves serve similar objectives to the system-wide VRR curve (See Section V.A.1), as applied to the Locational Deliverability Areas. However, there are some important differences regarding both reliability and pricing. Regarding reliability, PJM has always defined local targets as a 0.04 *conditional* LOLE (reliability index of 1-in-25), conditioned on the assumption that imports into the LDA are fully available (while the LDA is also subject to loss of load in the event of system-wide shortages). Although we discuss alternatives to this target in the following section, we evaluate local VRR curves in Section VI.B under the assumption that this traditional standard must be met on average across all LDAs under non-stressed modeling scenarios. As at the system level, it is also preferred to develop a curve that is robust to stress scenarios, including somewhat different types of stresses that can occur at the local level.

Regarding pricing, the primary objectives of mitigating price volatility and susceptibility to the exercise of market power remain the same. However, an essential difference from the system-wide market is that the realized price in the LDAs depends on either the system-wide VRR curve or the local VRR curve, depending on whether the transmission constraint is binding. Our simulation modeling results show that most LDAs can be expected to price separate a minority of the time once the system grows out of its current capacity surplus. Thus, the local curves cannot be analyzed in isolation, and any evaluation of pricing performance must recognize the prices that resources would receive and that loads would pay.

2. Definition of Locational Reliability Requirement

As noted above, PJM's local Reliability Requirements are set based on a 1-in-25 or 0.04 *conditional* LOLE standard. It 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.⁶⁴ Taken at face value, the local standard would appear to suggest that an import-constrained LDA would have higher reliability 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. Instead, the local 1-in-25 is a conditional

⁶⁴ See PJM (2014a), Section 2.2.

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 LOLE at different locations within PJM's footprint, with the estimated reliability not reported after considering this additive effect.

Beyond these potential discrepancies in LOLE 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.

To resolve this relative lack of transparency in realized reliability and also make apply a more uniform reliability standard across the region, we recommend that PJM consider revising the definition of the locational reliability requirements. One option would be to adopt a standard based on normalized EUE, which is the expected outage rate as a percentage of total load. This metric has been used in various international markets, and we believe it to be a more robust metric since its meaning is more uniform across different system sizes and load profiles.⁶⁵ Although we recognize that the reliability standards themselves are not within the triennial review scope, they are related to the scope. We believe it would be more meaningful to compare the consistency in the VRR curve reliability implications and to rationalize VRR curve prices across LDAs if locational reliability were measured using this more uniform metric across LDAs of different sizes and at different nested levels.

3. Reliability at the Price Cap

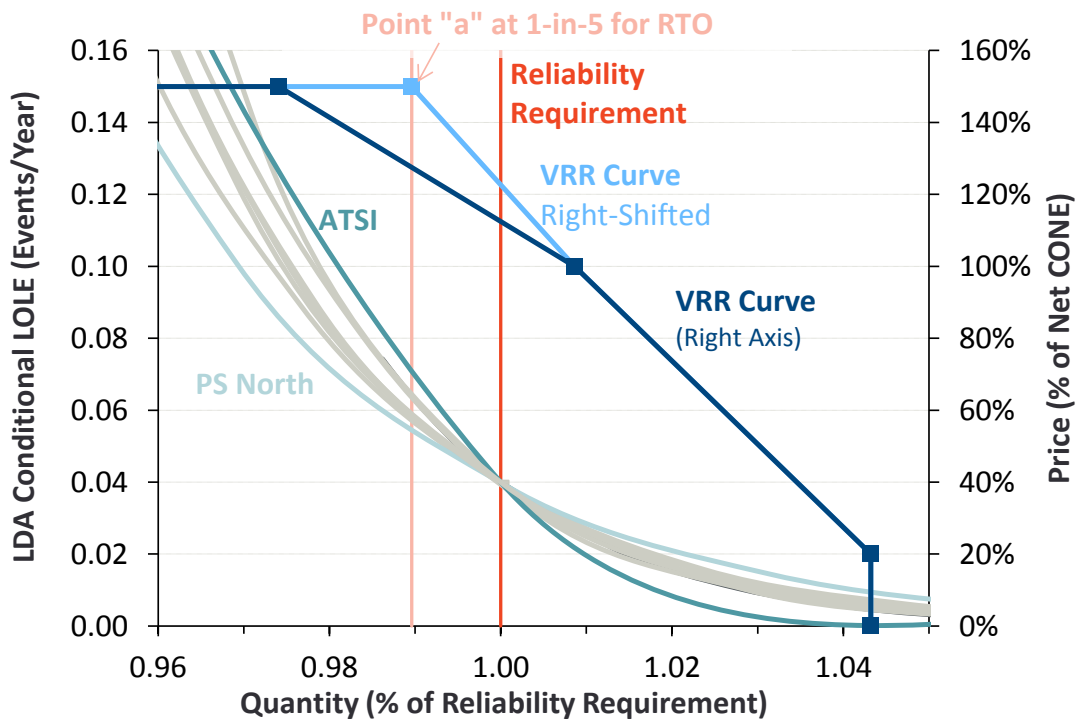
Similar to the system-level comparison of reliability metrics and the VRR curve from Section V.A.3, we compare the local VRR curves to the LDA conditional LOLE curves as shown in Figure 26. Again, we place particular emphasis on the shape of the curve at quantities below the Reliability

⁶⁵ Examples of metrics equivalent to Normalized EUE that are used in international markets include: (a) a 0.001% LOLP standard in Scandinavia; and (b) a 0.002% USE standard in Australia's National Energy Market (NEM) and South West Interconnected System (SWIS). See Nordel (2009), p. 5; AEMC (2007), pp. 29-30, (2010), p. viii.

Requirement, and similarly observe that rapidly increasing LOLE could result in very low reliability outcomes at moderate price levels. Based on the current VRR curve, prices would not reach the cap until reliability has substantially degraded to conditional LOLE values of approximately 0.086 to 0.138 (reliability index of 1-in-12 to 1-in-7, compared to a standard of 1-in-25) depending on the LDA.

These concerns could be similarly resolved by right-shifting the price cap. If PJM adopts our recommendation to right-shift the system curve cap to 1-in-5, then the same shift applied locally would result in substantially improved LOLE of approximately 0.051 to 0.068 (reliability index of 1-in-20 to 1-in-15) depending on the LDA.

Figure 26
Local VRR Curve Compared to Conditional Loss of Load Event
 (Without Adding Parent-LDA or System-Wide LOLE Events)



Sources and Notes:

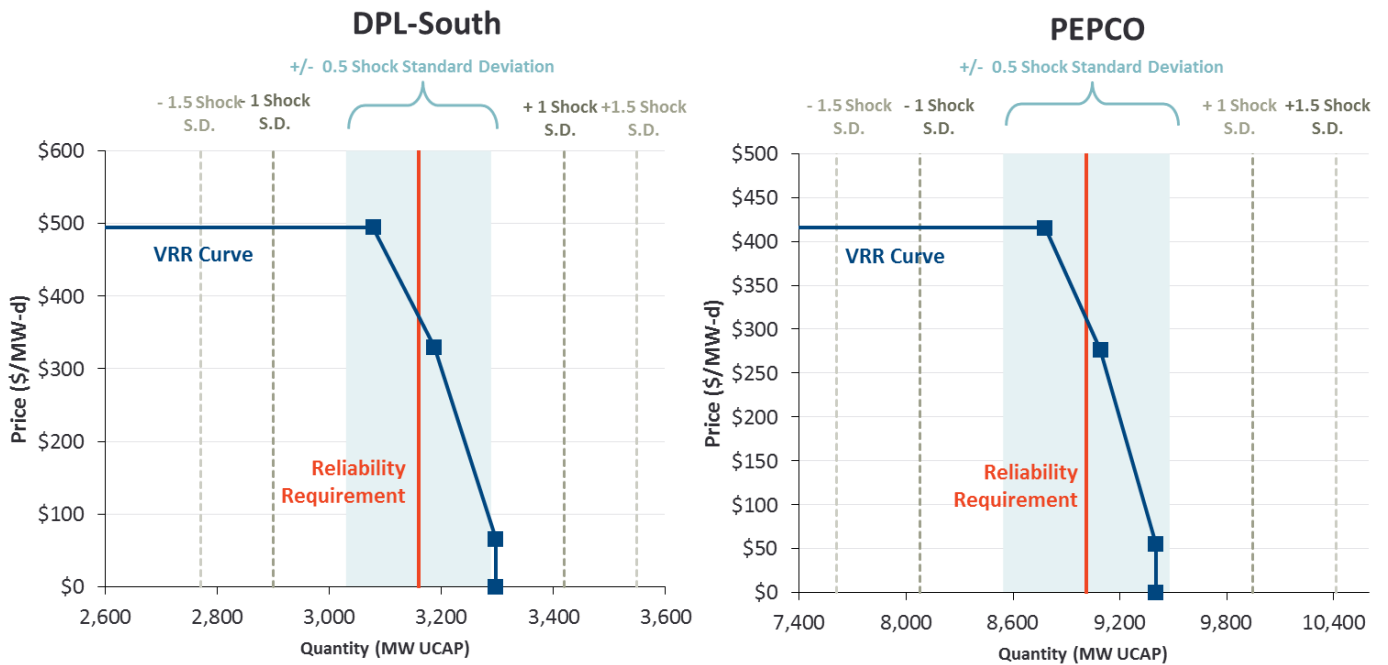
Current VRR Curve reflects the system VRR curve in the 2016/17 PJM Planning Parameters. See PJM (2013a.)
 The Conditional LOLE curves reflect the relationship between total quantity and reliability for each of the ten LDAs.

4. Width of the Curves Compared to Net Supply Shock Sizes

Similar to our analysis in Section V.A.4 above, we examine here the width of the locational VRR curves compared to expected year-to-year shocks to the net supply (including imports) minus demand at the local level. We show the width of the VRR curve compared to the standard deviation in net supply shocks for the largest and smallest LDAs (MAAC and DPL-South respectively) in Figure 27 and for all LDAs in Table 16.

Similar to our finding at the system-wide level, we observe that the year-to-year shocks to net supply minus demand at the local level are large relative to the width of the VRR curve. 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 more than three times the width of the entire VRR curve. For highly import-dependent LDAs, changes to the CETL also introduce a substantial source of volatility. For example, in the import-dependent LDA of PepCo, CETL would represent 76% of the Reliability Requirement whenever the LDA is import-constrained. A drop in the 2016/17 CETL by our estimated 12% standard deviation would correspond to an 822 MW drop in total supply, or more than 130% of the width of the entire VRR curve.

Figure 27
Locational VRR Curve Width Compared to Expected Net Supply Shocks



Sources and Notes:

Current VRR Curve reflects the DPL-South and PepCo VRR curves in the 2016/17 PJM Planning Parameters. See PJM (2013a.)
 The range of expected net supply shocks are based on simulated outcomes of supply minus demand shocks for DPL-S and PepCo.
 As reported in Table 5, the standard deviation of simulated shocks is 259 MW for DPL-S and 935 MW for PepCo.

Table 16
Locational VRR Curve Width Compared to Shock Sizes

LDA	VRR Curve Width (MW) [1]	Estimated Net Shocks St. Dev. (MW) [2]	Net Shocks as Percent of Curve Width (%) [3]
RTO	11,497	4,277	37%
MAAC	5,003	2,984	60%
EMAAC	2,747	1,954	71%
SWMAAC	1,198	1,214	101%
ATSI	1,125	1,186	105%
PSEG	891	908	102%
PEPCO	624	935	150%
PS-N	446	446	100%
ATSI-C	427	699	164%
DPL-S	219	259	119%

Notes:

[1]: Distance from 2016/17 VRR Curve Point "a" to Point "c",
See PJM (2013a).

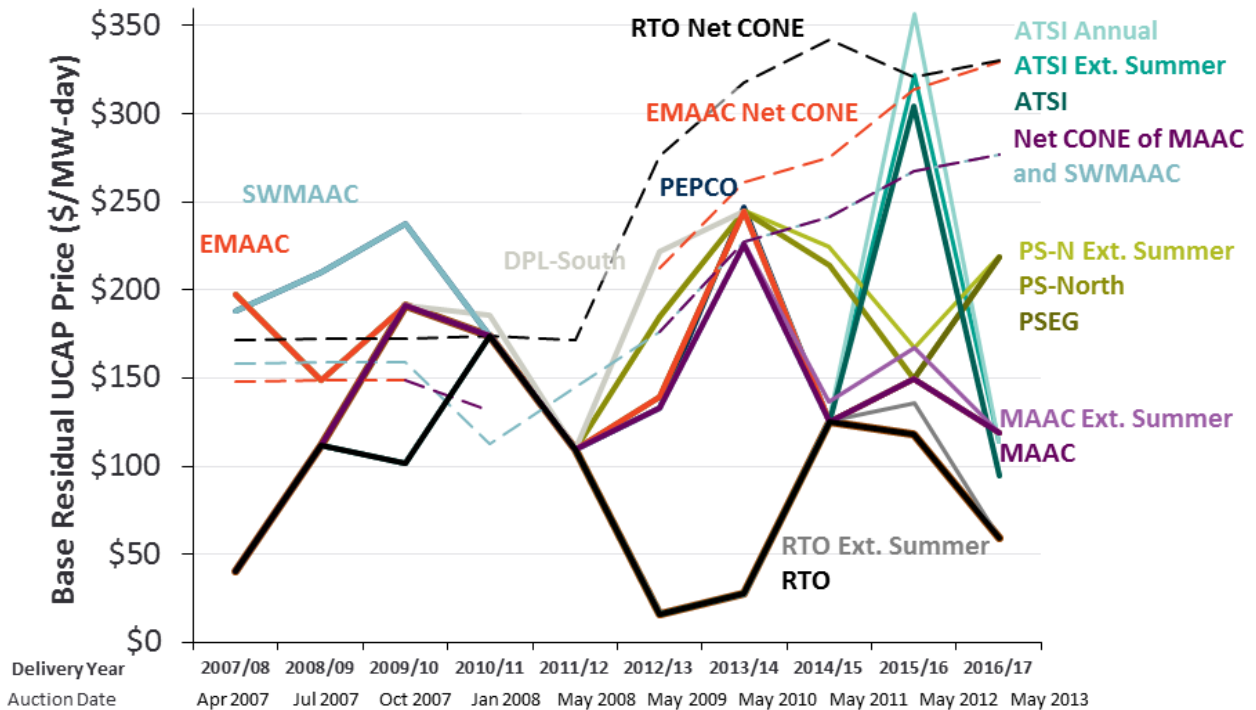
[2]: Equal to simulated net supply shocks by LDA from Table 5.

[3]: [2]/[1].

While these net shock 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 import-constrained 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 VI.B does account 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. We observe several examples of such events historically as shown in Figure 28. The biggest driver of these historical spikes has been sudden contractions in the estimated CETL for particular LDAs, which were the primary cause of the realized price spikes in MAAC, EMAAC, and SWMAAC in the auction for 2013/14. As at the system level, such price spikes at the local level introduce a greater level of uncertainty in the market, and consequently generate concern among market participants and other stakeholders.

Figure 28
Historical BRA Capacity Prices for Individual LDAs



Sources and Notes:

PJM Base Residual Auction Reports and Planning Parameters, See PJM (2007 – 2013a).

Mitigating the potential for low-reliability, high-price outcomes at the LDA level could be addressed in a number of ways, especially by changing the shape of the VRR curve. Low reliability events could be mitigated by shifting the curve to the right, thus providing price signals earlier and right-shifting the entire distribution of reserve margin outcomes. Alternatively or in addition, low reliability and high price events (and volatility) could both be mitigated by stretching the curve rightward, with the lower-priced parts of the curve shifting the furthest to the right. This too would work by providing price signals earlier and right-shifting the entire distribution of reserve margin outcomes. We would not recommend mitigating price volatility by simply flattening the curve with a left-shifted point “a” as that would introduce substantial risks of low-quantity events and reduce the incentives to locate capacity in import-constrained zones, as we explained in our 2011 review.⁶⁶ We more fully evaluate the price volatility, reliability, and customer cost tradeoffs among such potential changes to the local VRR curves based on results of a simulation analysis as in the following sections.

Changes to the locational VRR curve are not the only way to address these concerns. In particular, 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

⁶⁶ See 2011 RPM Review, Section V.D.2, pp. 109-111.

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.⁶⁷ 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 might, therefore, 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 the approach to modeling locational constraints in RPM beyond just import-constrained, nested LDAs with a single import limit. It is possible that some alternative approaches to modeling locational constraints could be less volatile than the current approach, for example an alternative zone structure might be able to better reflect the underlying transmission topology to be less sensitive to modeling assumptions factors such as load flow cases. The most generalized “meshed zone” approach would allow for the possibility that some locations may be export-constrained, may have multiple transmission import paths, or may have the possibility of being either import- or export-constrained, depending on RPM auction outcomes.⁶⁸ Adopting a generalized approach may also provide more accurate representation of underlying transmission constraints as reserve margins decrease and the number of modeled LDAs continues to increase. 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 following section.

5. Clearing Mechanics Rationalized for Locational Reliability Value

One reason that volatility in CETL has such a large impact in producing price spikes in LDAs is that transmission limits in RPM are treated as binary constraints in the auction clearing engine. This means that LDAs will tend to clear with parent zones most of the time, providing no incremental incentives to invest in an import-constrained LDA. Only under periodic short-supply shocks to supply, demand, or especially to CETL, will the LDA experience a price spike above the parent LDA, usually for just one year, before a small increase in net supply causes prices to collapse back to the parent value. The result is a structural volatility and propensity for price spikes in LDAs. To attract investment in an LDA with Net CONE above the parent LDA Net CONE, those spikes would need to be frequent enough and severe enough to achieve the higher local Net CONE on average.

⁶⁷ See our 2011 study, Pfeifenberger (2011), for a more comprehensive discussion of uncertainty in CETL and options for addressing the volatility in this parameter.

⁶⁸ We provide a more comprehensive discussion of “meshed” and “nested” approach to locational modeling in our 2011 RPM Review, Pfeifenberger (2011).

It would be more desirable from the perspective of both suppliers and customers if the same overall average price differential were produced in a more stable fashion, with RPM providing a modest price differential in most years (rather than a large price differential in only a few years). A smaller and more stable price differential also makes sense from an economic and reliability perspective because such prices would be more reflective of the higher reliability value of resources in import-constrained LDAs. This greater reliability value exists at all times, because resources in import-constrained zones contribute not only to RTO-level and parent-level reliability, like resources in those external LDAs, but also to local reliability in that LDA. Local resources help avoid local reliability events that external resources cannot always address, because dispatch conditions or transmission facility deratings may prevent them from doing so or alternately because as an LDA becomes more import-dependent load diversity benefits decline.⁶⁹ The value premium of local resources is of course smaller when local resources are plentiful, but it should change gradually rather than in a binary fashion as in PJM's current auction clearing mechanics. Recognizing this differential reliability value in the auction would allow prices to separate more gradually in proportion to reliability value as zones become more import constrained. Doing so might introduce more complexity into RPM parameters, but it could improve both the economics of price signals as well as the volatility of realized prices.

Defining appropriately gradual differentials in reliability value between resources locating in import-constrained LDAs and resources imported from the parent LDA would require enhancing PJM's reliability modeling. PJM could use the same multi-area reliability model it already uses to estimate system Reliability Requirements, but it would have to design its studies differently.⁷⁰ The studies would be designed to calculate the MW equivalence between LDA-internal resources and resources imported from the parent zone, for example, showing that relying on 100 MW more imports would provide only as much local LDA reliability value as adding 75 MW more local supply, at a given local reserve margin.⁷¹

⁶⁹ Similar to load diversity benefits or "tie benefits" among RTOs as studied in PJM's reliability studies, load diversity benefits also occur within sub-regions of the RTO. For example, if EMAAC peaks at a different time from MAAC as a whole, then EMAAC will typically be able to benefit from capacity resources that were committed primarily to meet the resource adequacy needs of other loads in MAAC. However, if EMAAC relies very heavily on imports even under normal and near-peak conditions, then there will be less unused import capability available during EMAAC's local peak. In that case, it will not be possible to import additional supplies even if other areas are not peaking (*i.e.*, some load diversity benefits have been lost).

⁷⁰ Implementing this calculation would require PJM to revise its locational modeling approach, which currently considers only one LDA at a time and does not simultaneously model reliability outcomes in multiple areas at once, which is necessary to account for lost load diversity benefits. This multi-area modeling capability could be developed through extensions to PJM's PRISM model that is currently used for local modeling, or could be implemented through vendor software packages such as GE MARS or Astrape's SERVIM. See Astrape Consulting (2014).

⁷¹ One approach to calculating this differential reliability value, as shown in the illustrative Figure 33, would be to: (1) model an import-constrained zone at its Reliability Requirement, with transmission fully

Continued on next page

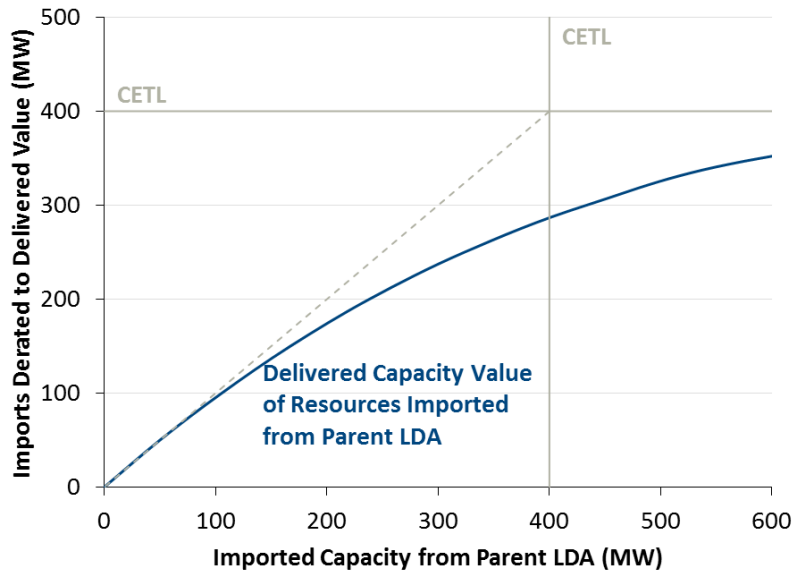
Figure 29 provides an illustrative example of such a calculation, showing the quantity of imports into an LDA on the x-axis, and the “delivered reliability value” of those imports on the y-axis. The chart illustrates that if an LDA has abundant local supply and is not relying heavily on imports, then increasing imports will have almost the same reliability value as adding local supply. Under a revised clearing mechanism, there would be no or only a small price differential from the parent LDA since 1 MW of imports would provide the same reliability value as 1 MW of local supply.

However, as the LDA becomes more import-dependent, the realized reliability value of external resources diminishes, and local supply becomes relatively more valuable. In this example, when the LDA is importing 300 MW total from the parent LDA, an additional 1 MW of imported capacity provides only as much reliability value as 0.75 MW of local supply. If the parent LDA price were \$100/MW-d in this case, the auction clearing algorithm would treat imported resources as if they had a cost of $\$100 / 0.75 \text{ delivered MW} = \$133/\text{MW-d}$. The auction would select the lowest cost resources between imports at \$133/MW-d (delivered MW value) and locally-sourced supply.

Continued from previous page

import-constrained at CETL and local reliability at the reliability standard; (2) conduct a series of simulation runs where supply is moved from the parent LDA into the import-constrained LDA, with local supply increasing over quantities starting at Reliability Requirement minus CETL, up to the total Reliability Requirement (thereby reducing the level of import dependence from the maximum value down to zero), with the resulting level of import-dependence shown as the figure x-axis; (3) at each level of import-dependence, calculate the marginal avoided EUE in the LDA if adding 1 MW of supply locally, compared to marginal avoided EUE in the LDA if adding 1 MW of supply in the parent LDA; and (4) calculating the “delivered capacity value” into the import-constrained LDA based on this ratio, shown as the figure y-axis. Note that this methodology requires that the local reliability be calculated as the total LOLE including LOLE from local events, parent events, and system-level events. The method would also reflect a more rational calculation if implemented according to a normalized EUE metric, rather than an LOLE metric, which is why we describe it this way. However, alternative methods could be developed that rely on LOLE instead of EUE.

Figure 29
Delivered Capacity Value vs. Level of LDA Import Dependence



Note:
 Illustrative figure does not reflect actual simulation data.

B. SIMULATED PERFORMANCE OF SYSTEM CURVES APPLIED LOCALLY

In this Section, we present simulation analyses of the performance of the current VRR curve, as well as the 1.5× Convex Tuned, 1.7× Convex Tuned, and 1.5× Convex Right-Shifted curves that we developed at the system level in Section V.C above. To test the performance of these curves, we evaluate them primarily against 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. We find that neither the current VRR curve nor the 1.5× Convex Tuned curve is likely to meet the 0.04 LOLE target on average across all LDAs in this non-stress scenario, although the 1.7× Convex Tuned and right-shifted curves would do so. The relatively poorer reliability performance of the curves at the local level is due primarily to the disproportionate impact of shocks to supply, demand, and CETL in smaller areas.

We also test the sensitivity of this performance to administrative errors in Net CONE and to modeling uncertainties, finding that the current curve is the least robust of these options. We also find that the 1.5× Convex Tuned curve that we recommend at the system level performs better than the current curve as applied at the local level, but still falls short of performance and robustness objectives. This is particularly true in the most import-dependent and smallest LDAs, which are more susceptible to errors in Net CONE and have proportionately greater exposure to shocks.

1. Performance under Base Case Assumptions

Table 17 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. We report these Base Case values for reference, although these results provide limited insight regarding the performance of the VRR curve as applied at the local level. This is because, consistent with the 2016/17 BRA parameters, we adopt a Base Case assumption in which most LDAs have Net CONE below the RTO Net CONE.

As we noted in Section III.C.3, if an import-constrained LDA has a lower Net CONE, then we would expect new supplies to locate in that location. The local VRR curve might eventually become a non-binding constraint (or will not be modeled at all), leaving local price and reliability results will converge to parent or RTO levels. Our simulation model discovered this intuitive result, as shown in Table 17. In that trivial case, there are no local reliability concerns, and any adjustments to the VRR curve would be irrelevant in the long term. (Recall that all simulation results reflect long-term equilibrium conditions in which annual outcomes fluctuate but long-term average prices equal Net CONE, not current or near-term market conditions).

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. Thus, VRR curves should be designed to perform well in this case, being otherwise irrelevant in the long-term. We also believe this case will usually be the most likely if import-constrained areas tend to be import-constrained because costs are greater there. Even in cases where Net CONE appears lower in an LDA, it may be because of an error in estimating CONE or E&AS offsets, as we demonstrated for SWMAAC in Section III.B.1. In other cases, Net CONE may appear lower only temporarily until new entrants reduce the local energy price premium. Therefore, in the remainder of our analysis we analyze only cases where each LDA is import-constrained, with a higher Net CONE than the parent LDA.

Table 17
Performance of VRR Curve in LDAs under Base Case Assumptions

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Rel. Req. Above	St. Dev. (MW)	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	(\$/MW-d)	(\$/MW-d)	(%)	(%)	(Ev/Yr)	(Ev/Yr)	(MW)	(MW)	(%)	(%)	(%)	(%)	(\$mil)	(\$mil)	(\$mil)
Current VRR Curve															
MAAC	\$331	\$95	6%	0%	0.000	0.121	***	***	***	***	***	***	\$8,040	\$5,056	\$11,220
EMAAC	\$330	\$95	6%	0%	0.000	0.122	***	***	***	***	***	***	\$4,376	\$2,761	\$6,103
SWMAAC	\$331	\$95	6%	0%	0.000	0.121	***	***	***	***	***	***	\$1,855	\$1,167	\$2,594
ATSI	\$363	\$116	13%	29%	0.073	0.195	795	1,114	105%	7%	23%	19%	\$1,904	\$1,134	\$2,705
PSEG	\$330	\$95	6%	0%	0.000	0.122	***	***	***	***	***	***	\$1,393	\$880	\$1,943
PEPCO	\$331	\$95	6%	0%	0.000	0.121	***	***	***	***	***	***	\$895	\$566	\$1,247
PS-N	\$330	\$95	6%	0%	0.000	0.122	***	***	***	***	***	***	\$676	\$425	\$945
ATSI-C	\$363	\$116	13%	0%	0.000	0.195	***	***	***	***	***	***	\$680	\$391	\$1,016
DPL-S	\$330	\$95	6%	0%	0.000	0.122	***	***	***	***	***	***	\$320	\$200	\$448

Notes:

*** An arbitrary quantity of excess supply is attracted into an LDA with Net CONE below system Net CONE.

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.

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 this section, we also compare the performance to that of three enhanced VRR curve shapes that we analyzed for the system above, and we will identify improvements but shortfalls with the alternatives tested. The following Section VI.C will present more alternative shapes, including special modifications tuned to local areas. Finally, Section VI.D presents our overall recommendations for modifying local VRR curves to meet reliability objectives, including in the most vulnerable import-dependent LDAs.

In Table 18, 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 19, 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, and ATSI-C) have a substantially higher Net CONE that is 20% above the parent LDA value. For example, PS-North would have a 35% 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 true developer Net CONE.

Under the 5% higher case, we observe that the current VRR curve falls short of the local Reliability Requirement of 1-in-25 (or 0.04 LOLE) in four of nine LDAs, and produces a frequency of low reliability events below 1-in-15 in three 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. By comparison, all three of the alternative VRR curves developed in Section V above show better reliability performance, with: (a) the 1.5× Convex curve showing modest improvement but also falling short of Reliability Requirements in three LDAs, and (b) the 1.7× Convex curve and the Right-Shifted Convex curve meeting or slightly exceeding the reliability Requirements in all cases.

In terms of price volatility, we observe that, similar to our system-wide results, the VRR Curve performs somewhat better than the convex curves, primarily because the concave shape mitigates the impact of price volatility in the high-price region (which also has the problematic effect of increasing the frequency of very low reliability events).

In the more stressed case reflected in Table 19, we see that the locations with Net CONE 20% above the parent all fail to meet the reliability objective under the current VRR curve as well as under all of the alternative curves. The two poorest-performing LDAs in this case are the most import-dependent locations of PepCo and ATSI-C, showing very low reliability levels of approximately 1-in-2 and 1-in-1 respectively under the current VRR Curve. Each of the convex curves shows

improvement in reliability relative to the current VRR curve, but the most import-constrained LDAs continue to fail to meet the Reliability Requirement in all cases. The best-performing curve is the 1.7× Convex curve, under which reliability events drop by half but still remain an order of magnitude above the target level.

These results demonstrate that the current VRR curve will achieve local reliability objectives only under certain conditions, and would be unlikely to achieve reliability objectives in the most import-dependent locations or in those with Net CONE substantially above the parent value. The alternative VRR curves that we analyzed for the system would improve reliability outcomes, with the 1.7× Convex curve showing the most improvement and meeting reliability objectives in most LDAs if local Net CONE values only modestly exceed parent levels. However, none of the curves we analyzed for the system is robust to a circumstance with substantially higher Net CONE in an LDA, with all curves showing very poor reliability in the most import-dependent LDAs. The following two sections will show how performance could deteriorate even further if Net CONE is underestimated or if shocks are larger than in our Base modeling assumptions.

Table 18
VRR and Alternative Curves' Performance with Net CONE always 5% Higher than Parent Net CONE

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req. (MW)	St. Dev. (MW)	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	(\$/MW-d)	(\$/MW-d)	(%)	(%)	(Ev/Yr)	(Ev/Yr)	(MW)	(MW)	(%)	(%)	(%)	(%)	(\$mil)	(\$mil)	(\$mil)
Current VRR Curve															
MAAC	\$277	\$89	12%	33%	0.053	0.160	1,389	2,356	102%	3%	27%	17%	\$7,218	\$4,199	\$10,669
EMAAC	\$291	\$98	8%	25%	0.033	0.193	1,349	1,706	103%	4%	22%	15%	\$4,058	\$2,275	\$6,049
SWMAAC	\$291	\$96	6%	17%	0.042	0.202	1,215	1,163	107%	7%	14%	8%	\$1,689	\$969	\$2,504
ATSI	\$277	\$87	11%	18%	0.035	0.143	1,152	1,121	107%	7%	14%	11%	\$1,476	\$904	\$2,120
PSEG	\$305	\$105	5%	15%	0.022	0.215	1,036	886	108%	7%	13%	9%	\$1,350	\$730	\$2,002
PEPCO	\$305	\$104	25%	14%	0.064	0.266	1,099	923	112%	10%	11%	10%	\$857	\$471	\$1,292
PS-N	\$321	\$116	31%	15%	0.023	0.238	503	442	108%	7%	12%	8%	\$687	\$361	\$1,047
ATSI-C	\$291	\$95	10%	12%	0.059	0.202	906	694	115%	11%	9%	8%	\$533	\$316	\$796
DPL-S	\$305	\$105	13%	15%	0.027	0.220	309	259	110%	8%	12%	7%	\$308	\$167	\$464
Convex Tuned, 1.5x Cap															
MAAC	\$277	\$97	14%	31%	0.043	0.131	1,615	2,315	102%	3%	23%	14%	\$7,231	\$4,045	\$11,064
EMAAC	\$291	\$107	12%	23%	0.027	0.158	1,536	1,694	104%	4%	18%	11%	\$4,065	\$2,194	\$6,293
SWMAAC	\$291	\$104	8%	16%	0.034	0.165	1,311	1,159	108%	7%	12%	7%	\$1,692	\$934	\$2,604
ATSI	\$277	\$95	9%	17%	0.030	0.117	1,232	1,118	108%	7%	12%	9%	\$1,479	\$878	\$2,209
PSEG	\$305	\$114	8%	14%	0.019	0.177	1,106	885	109%	7%	11%	7%	\$1,353	\$698	\$2,073
PEPCO	\$305	\$111	9%	14%	0.055	0.219	1,138	922	113%	10%	10%	8%	\$858	\$454	\$1,337
PS-N	\$321	\$123	8%	14%	0.019	0.196	537	443	108%	7%	10%	6%	\$688	\$342	\$1,077
ATSI-C	\$291	\$102	7%	11%	0.048	0.166	943	695	115%	11%	9%	7%	\$534	\$303	\$822
DPL-S	\$305	\$113	7%	15%	0.023	0.182	323	259	110%	8%	10%	6%	\$309	\$160	\$480
Convex Tuned, 1.7x Cap															
MAAC	\$277	\$115	12%	27%	0.039	0.133	1,595	2,202	102%	3%	21%	12%	\$7,199	\$3,657	\$11,865
EMAAC	\$291	\$126	11%	20%	0.023	0.156	1,643	1,658	104%	4%	16%	9%	\$4,047	\$1,965	\$6,747
SWMAAC	\$291	\$122	7%	13%	0.028	0.161	1,367	1,145	108%	7%	11%	6%	\$1,683	\$849	\$2,788
ATSI	\$277	\$113	7%	14%	0.024	0.118	1,313	1,112	108%	7%	11%	8%	\$1,472	\$792	\$2,391
PSEG	\$305	\$134	7%	12%	0.016	0.172	1,160	882	109%	7%	10%	6%	\$1,348	\$634	\$2,243
PEPCO	\$305	\$131	7%	11%	0.034	0.194	1,234	915	114%	10%	9%	6%	\$851	\$410	\$1,430
PS-N	\$321	\$145	6%	12%	0.015	0.187	580	439	109%	7%	9%	5%	\$685	\$308	\$1,177
ATSI-C	\$291	\$120	6%	9%	0.035	0.153	1,001	695	116%	11%	7%	6%	\$531	\$274	\$875
DPL-S	\$305	\$134	6%	12%	0.020	0.177	336	259	111%	8%	9%	6%	\$306	\$145	\$514
Convex 1.5x, Right-Shifted															
MAAC	\$277	\$97	14%	31%	0.028	0.080	2,237	2,314	103%	3%	15%	9%	\$7,295	\$4,087	\$11,175
EMAAC	\$291	\$107	13%	23%	0.020	0.100	1,879	1,694	105%	4%	14%	8%	\$4,102	\$2,211	\$6,350
SWMAAC	\$291	\$104	8%	16%	0.024	0.105	1,460	1,159	108%	7%	8%	6%	\$1,707	\$941	\$2,627
ATSI	\$277	\$95	9%	17%	0.022	0.074	1,373	1,118	108%	7%	10%	7%	\$1,492	\$886	\$2,229
PSEG	\$305	\$114	8%	14%	0.014	0.114	1,218	885	109%	7%	9%	5%	\$1,365	\$706	\$2,094
PEPCO	\$305	\$111	9%	14%	0.040	0.144	1,224	922	114%	10%	9%	7%	\$866	\$458	\$1,349
PS-N	\$321	\$123	8%	14%	0.015	0.129	593	443	109%	7%	8%	5%	\$694	\$345	\$1,087
ATSI-C	\$291	\$102	7%	11%	0.036	0.110	999	695	116%	11%	8%	6%	\$539	\$306	\$831
DPL-S	\$305	\$113	7%	14%	0.018	0.118	351	259	111%	8%	7%	5%	\$311	\$162	\$484

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

Table 19
Performance with LDA Net CONE 5% Higher than Parent (for Most LDAs)
or 20% Higher (Most Import-Constrained LDAs of PS-North, DPL-South, PepCo, and ATSI-C)

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req. (MW)	St. Dev. (MW)	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	(\$/MW-d)	(\$/MW-d)	(%)	(%)	(Ev/Yr)	(Ev/Yr)	(MW)	(MW)	(%)	(%)	(%)	(%)	(\$mil)	(\$mil)	(\$mil)
Current VRR Curve															
MAAC	\$277	\$89	8%	33%	0.054	0.162	1,380	2,364	102%	3%	27%	17%	\$7,342	\$4,311	\$10,760
EMAAC	\$291	\$99	10%	25%	0.034	0.196	1,335	1,709	103%	4%	23%	15%	\$4,138	\$2,340	\$6,100
SWMAAC	\$291	\$96	8%	17%	0.043	0.205	1,221	1,167	107%	7%	14%	9%	\$1,730	\$1,005	\$2,523
ATSI	\$277	\$87	8%	18%	0.036	0.145	1,143	1,123	107%	7%	15%	11%	\$1,495	\$923	\$2,131
PSEG	\$305	\$106	9%	14%	0.022	0.218	1,046	888	108%	7%	13%	9%	\$1,411	\$761	\$2,066
PEPCO	\$349	\$131	12%	35%	0.487	0.693	504	900	106%	10%	28%	24%	\$913	\$504	\$1,332
PS-N	\$366	\$142	12%	40%	0.075	0.293	209	430	103%	7%	31%	21%	\$755	\$375	\$1,129
ATSI-C	\$332	\$120	12%	32%	0.765	0.910	425	687	107%	11%	25%	22%	\$566	\$326	\$824
DPL-S	\$349	\$132	12%	36%	0.126	0.322	146	253	105%	8%	28%	22%	\$335	\$175	\$500
Convex Tuned, 1.5x Cap															
MAAC	\$277	\$98	14%	31%	0.044	0.132	1,604	2,319	102%	3%	23%	14%	\$7,358	\$4,148	\$11,152
EMAAC	\$291	\$107	13%	24%	0.028	0.160	1,523	1,697	104%	4%	19%	12%	\$4,147	\$2,227	\$6,340
SWMAAC	\$291	\$104	8%	16%	0.034	0.166	1,317	1,162	108%	7%	12%	7%	\$1,733	\$969	\$2,630
ATSI	\$277	\$95	9%	17%	0.030	0.118	1,232	1,119	108%	7%	12%	9%	\$1,498	\$893	\$2,213
PSEG	\$305	\$114	9%	14%	0.019	0.178	1,108	885	109%	7%	11%	8%	\$1,415	\$719	\$2,139
PEPCO	\$349	\$137	23%	35%	0.423	0.589	540	899	106%	10%	26%	22%	\$914	\$488	\$1,382
PS-N	\$366	\$149	22%	39%	0.067	0.245	237	429	104%	7%	28%	19%	\$757	\$356	\$1,154
ATSI-C	\$332	\$127	21%	31%	0.630	0.748	461	686	108%	11%	23%	21%	\$567	\$317	\$850
DPL-S	\$349	\$139	21%	35%	0.107	0.267	164	253	105%	8%	26%	20%	\$336	\$166	\$511
Convex Tuned, 1.7x Cap															
MAAC	\$277	\$116	12%	26%	0.040	0.134	1,590	2,210	102%	3%	22%	12%	\$7,323	\$3,729	\$12,006
EMAAC	\$291	\$126	11%	19%	0.024	0.158	1,647	1,662	104%	4%	16%	10%	\$4,128	\$2,022	\$6,830
SWMAAC	\$291	\$123	7%	14%	0.029	0.163	1,361	1,147	108%	7%	11%	6%	\$1,726	\$864	\$2,830
ATSI	\$277	\$113	8%	14%	0.024	0.119	1,312	1,111	108%	7%	11%	8%	\$1,494	\$814	\$2,391
PSEG	\$305	\$134	7%	12%	0.016	0.174	1,151	882	109%	7%	10%	6%	\$1,408	\$648	\$2,320
PEPCO	\$349	\$163	18%	28%	0.244	0.407	678	894	108%	10%	21%	17%	\$909	\$429	\$1,488
PS-N	\$366	\$178	18%	31%	0.050	0.224	297	426	105%	7%	23%	15%	\$754	\$321	\$1,270
ATSI-C	\$332	\$151	17%	25%	0.379	0.498	543	684	109%	11%	19%	17%	\$562	\$285	\$896
DPL-S	\$349	\$165	18%	29%	0.077	0.235	194	253	106%	8%	22%	16%	\$334	\$149	\$556
Convex 1.5x, Right-Shifted															
MAAC	\$277	\$98	14%	31%	0.029	0.081	2,231	2,319	103%	3%	15%	9%	\$7,424	\$4,185	\$11,258
EMAAC	\$291	\$107	13%	24%	0.020	0.102	1,866	1,697	105%	4%	14%	8%	\$4,183	\$2,247	\$6,400
SWMAAC	\$291	\$104	8%	16%	0.024	0.105	1,472	1,162	109%	7%	8%	6%	\$1,749	\$978	\$2,659
ATSI	\$277	\$95	9%	17%	0.023	0.075	1,367	1,119	108%	7%	10%	7%	\$1,512	\$901	\$2,233
PSEG	\$305	\$114	9%	14%	0.014	0.115	1,219	885	109%	7%	9%	5%	\$1,428	\$726	\$2,158
PEPCO	\$349	\$137	23%	35%	0.318	0.423	620	899	107%	10%	23%	20%	\$923	\$493	\$1,396
PS-N	\$366	\$149	22%	39%	0.053	0.168	293	429	105%	7%	23%	16%	\$764	\$359	\$1,166
ATSI-C	\$332	\$127	21%	31%	0.480	0.555	511	686	108%	11%	21%	18%	\$573	\$319	\$859
DPL-S	\$349	\$139	21%	35%	0.083	0.185	191	253	106%	8%	22%	17%	\$339	\$168	\$516

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

3. Sensitivity to Errors in Administrative 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 as we recommended in Section III 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.

As at the system level, underestimating Net CONE results in substantially degraded reliability under the current VRR curve as well as all of the alternative curves. However, the alternative curves are more robust to these errors, with the 1.7× Convex curve showing some LDAs that continue to meet the reliability standard, and reducing the frequency of load-shed events by 50-65% depending on the LDA. These results indicate that increasing the price cap at the LDA level would be a beneficial protection against low reliability events. We further examine this option, along with alternative approaches for addressing these concerns, in Section VI.C.1 below.

Table 20
VRR Curve Performance with 20% Under-Estimate in Net CONE
(True Net CONE 5% Higher than Parent)

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req. (MW)	St. Dev. (MW)	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	(\$/MW-d)	(\$/MW-d)	(%)	(%)	(Ev/Yr)	(Ev/Yr)	(MW)	(MW)	(%)	(%)	(%)	(%)	(\$mil)	(\$mil)	(\$mil)
Current VRR Curve															
MAAC	\$277	\$63	24%	52%	0.219	0.518	-365	2,570	100%	4%	54%	41%	\$7,175	\$4,862	\$9,333
EMAAC	\$291	\$70	25%	40%	0.103	0.621	151	1,790	100%	5%	46%	34%	\$4,032	\$2,644	\$5,301
SWMAAC	\$291	\$67	22%	29%	0.180	0.699	593	1,182	103%	7%	32%	24%	\$1,684	\$1,116	\$2,192
ATSI	\$277	\$61	22%	31%	0.128	0.427	528	1,137	103%	7%	33%	27%	\$1,464	\$1,022	\$1,882
PSEG	\$305	\$73	22%	26%	0.085	0.706	512	897	104%	7%	28%	22%	\$1,340	\$866	\$1,745
PEPCO	\$305	\$71	22%	24%	0.404	1.103	639	934	107%	10%	25%	21%	\$857	\$554	\$1,132
PS-N	\$321	\$78	21%	27%	0.076	0.782	233	446	104%	7%	30%	21%	\$683	\$426	\$901
ATSI-C	\$291	\$65	20%	20%	0.445	0.873	543	694	109%	11%	20%	18%	\$533	\$357	\$704
DPL-S	\$305	\$73	21%	24%	0.106	0.727	175	259	106%	8%	26%	20%	\$307	\$194	\$409
Convex Tuned, 1.5x Cap															
MAAC	\$277	\$70	33%	49%	0.161	0.382	36	2,516	100%	3%	45%	33%	\$7,209	\$4,494	\$9,562
EMAAC	\$291	\$76	30%	41%	0.084	0.466	384	1,771	101%	4%	39%	29%	\$4,053	\$2,464	\$5,406
SWMAAC	\$291	\$73	22%	28%	0.139	0.521	714	1,178	104%	7%	27%	20%	\$1,692	\$1,041	\$2,242
ATSI	\$277	\$68	23%	31%	0.104	0.326	630	1,129	104%	7%	29%	23%	\$1,475	\$949	\$1,943
PSEG	\$305	\$79	21%	25%	0.070	0.536	593	895	105%	7%	25%	20%	\$1,347	\$802	\$1,790
PEPCO	\$305	\$77	19%	24%	0.318	0.840	703	932	108%	10%	22%	18%	\$861	\$518	\$1,156
PS-N	\$321	\$84	21%	27%	0.064	0.600	274	445	104%	7%	26%	19%	\$687	\$401	\$917
ATSI-C	\$291	\$71	15%	19%	0.334	0.659	596	694	110%	11%	18%	15%	\$536	\$333	\$724
DPL-S	\$305	\$79	18%	24%	0.083	0.549	201	259	106%	8%	23%	17%	\$309	\$180	\$417
Convex Tuned, 1.7x Cap															
MAAC	\$277	\$90	27%	41%	0.106	0.290	417	2,364	101%	3%	40%	27%	\$7,197	\$3,948	\$10,566
EMAAC	\$291	\$98	23%	30%	0.057	0.347	774	1,713	102%	4%	31%	22%	\$4,043	\$2,144	\$5,977
SWMAAC	\$291	\$94	16%	22%	0.082	0.372	940	1,166	105%	7%	21%	14%	\$1,687	\$913	\$2,466
ATSI	\$277	\$87	16%	23%	0.064	0.248	852	1,114	105%	7%	23%	17%	\$1,468	\$851	\$2,088
PSEG	\$305	\$103	15%	19%	0.038	0.385	836	890	107%	7%	18%	13%	\$1,345	\$691	\$1,970
PEPCO	\$305	\$99	14%	18%	0.146	0.518	892	924	110%	10%	17%	13%	\$857	\$452	\$1,269
PS-N	\$321	\$110	14%	20%	0.040	0.425	377	443	106%	7%	19%	12%	\$685	\$339	\$1,011
ATSI-C	\$291	\$92	12%	15%	0.153	0.401	737	694	112%	11%	14%	12%	\$533	\$297	\$779
DPL-S	\$305	\$102	12%	18%	0.045	0.392	259	258	108%	8%	17%	12%	\$307	\$159	\$460
Convex 1.5x, Right-Shifted															
MAAC	\$277	\$70	33%	49%	0.106	0.247	663	2,516	101%	3%	36%	27%	\$7,275	\$4,522	\$9,642
EMAAC	\$291	\$76	31%	41%	0.064	0.310	716	1,771	102%	4%	32%	24%	\$4,089	\$2,484	\$5,451
SWMAAC	\$291	\$73	22%	29%	0.103	0.350	859	1,178	105%	7%	23%	17%	\$1,708	\$1,050	\$2,262
ATSI	\$277	\$68	23%	31%	0.079	0.220	776	1,129	105%	7%	24%	19%	\$1,489	\$955	\$1,960
PSEG	\$305	\$79	21%	25%	0.054	0.364	701	895	105%	7%	21%	17%	\$1,359	\$808	\$1,805
PEPCO	\$305	\$77	19%	24%	0.243	0.593	778	932	109%	10%	20%	16%	\$869	\$524	\$1,167
PS-N	\$321	\$84	21%	27%	0.049	0.413	335	445	105%	7%	22%	14%	\$694	\$404	\$926
ATSI-C	\$291	\$71	15%	19%	0.246	0.466	653	694	111%	11%	16%	14%	\$541	\$337	\$731
DPL-S	\$305	\$79	18%	24%	0.064	0.375	228	259	107%	8%	19%	15%	\$312	\$182	\$421

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

4. Sensitivity to Modeling Uncertainties

As we did at the system level, we also tested robustness of our conclusions at the LDA level under alternative modeling assumptions, after introducing 33% larger shocks, 33% smaller shocks, or eliminating all CETL shocks. With larger or smaller shocks, results are consistent with our expectations. We see that price volatility increases and reliability decreases with 33% larger shocks,

and that the reverse is true with smaller shocks. If shocks are 33% lower than under our base assumptions, then the current VRR Curve would achieve reliability objectives in all LDAs. With 33% higher shocks reliability would be substantially worse in all LDAs, with only two of nine LDAs meeting the reliability target.

Eliminating shocks to CETL has a large effect in improving reliability in the most import-dependent zones, as expected. However, removing these shocks in the larger and less import-dependent LDAs has minimal reliability impacts, with the primary effects being a reduction in the quantity of excess supply in that location, which, therefore, causes an increase in the frequency of price separation above the parent LDA, although the smaller shocks reduce the scale of the price spikes associated with price separation and also reduce the frequency of price-cap events.⁷²

⁷² This is because: (a) reductions in CETL volatility reduce the frequency of low quantity, high-price events, reducing prices closer to parent zone prices more often; (b) the result of the lower prices is a lower quantity of supply locating in those zones (this is the largest effect of removing CETL volatility); until (c) the lower quantity, combined with other shocks to supply and demand, result frequent enough price spikes to increase prices back up to Net CONE.

Table 21
VRR Curve Performance Sensitivity to Modeling Uncertainties
(Net CONE 5% Higher than Parent)

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req. (MW)	St. Dev. (MW)	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	(\$/MW-d)	(\$/MW-d)	(%)	(%)	(Ev/Yr)	(Ev/Yr)	(MW)	(MW)	(%)	(%)	(%)	(%)	(\$mil)	(\$mil)	(\$mil)
Base Shocks															
MAAC	\$277	\$89	12%	33%	0.053	0.160	1,389	2,356	102%	3%	27%	17%	\$7,218	\$4,199	\$10,669
EMAAC	\$291	\$98	8%	25%	0.033	0.193	1,349	1,706	103%	4%	22%	15%	\$4,058	\$2,275	\$6,049
SWMAAC	\$291	\$96	6%	17%	0.042	0.202	1,215	1,163	107%	7%	14%	8%	\$1,689	\$969	\$2,504
ATSI	\$277	\$87	11%	18%	0.035	0.143	1,152	1,121	107%	7%	14%	11%	\$1,476	\$904	\$2,120
PSEG	\$305	\$105	5%	15%	0.022	0.215	1,036	886	108%	7%	13%	9%	\$1,350	\$730	\$2,002
PEPCO	\$305	\$104	25%	14%	0.064	0.266	1,099	923	112%	10%	11%	10%	\$857	\$471	\$1,292
PS-N	\$321	\$116	31%	15%	0.023	0.238	503	442	108%	7%	12%	8%	\$687	\$361	\$1,047
ATSI-C	\$291	\$95	10%	12%	0.059	0.202	906	694	115%	11%	9%	8%	\$533	\$316	\$796
DPL-S	\$305	\$105	13%	15%	0.027	0.220	309	259	110%	8%	12%	7%	\$308	\$167	\$464
Zero CETL Shocks															
MAAC	\$277	\$90	9%	35%	0.051	0.160	1,163	2,202	102%	3%	29%	19%	\$7,207	\$4,066	\$10,918
EMAAC	\$291	\$101	11%	40%	0.044	0.204	650	1,374	102%	3%	32%	20%	\$4,062	\$2,245	\$6,206
SWMAAC	\$291	\$99	10%	36%	0.048	0.207	334	623	102%	4%	28%	17%	\$1,705	\$945	\$2,600
ATSI	\$277	\$92	10%	29%	0.036	0.145	430	620	103%	4%	24%	17%	\$1,492	\$848	\$2,229
PSEG	\$305	\$107	7%	31%	0.034	0.238	226	388	102%	3%	27%	14%	\$1,362	\$735	\$2,078
PEPCO	\$305	\$105	8%	28%	0.035	0.243	270	378	103%	4%	24%	15%	\$881	\$469	\$1,371
PS-N	\$321	\$115	9%	31%	0.036	0.274	144	255	102%	4%	29%	13%	\$698	\$357	\$1,081
ATSI-C	\$291	\$99	6%	25%	0.030	0.175	171	217	103%	4%	22%	15%	\$551	\$297	\$874
DPL-S	\$305	\$107	7%	27%	0.032	0.236	87	119	103%	4%	21%	12%	\$313	\$165	\$485
33% Higher Shocks															
MAAC	\$277	\$106	13%	32%	0.115	0.267	1,612	3,139	102%	4%	29%	21%	\$7,202	\$3,617	\$11,171
EMAAC	\$291	\$115	11%	24%	0.047	0.314	1,743	2,269	104%	6%	22%	17%	\$4,046	\$1,970	\$6,360
SWMAAC	\$291	\$113	7%	16%	0.082	0.349	1,648	1,539	110%	9%	13%	10%	\$1,685	\$842	\$2,621
ATSI	\$277	\$103	9%	17%	0.068	0.220	1,524	1,491	109%	9%	15%	12%	\$1,471	\$791	\$2,232
PSEG	\$305	\$122	7%	14%	0.032	0.346	1,402	1,178	111%	9%	13%	10%	\$1,346	\$627	\$2,096
PEPCO	\$305	\$120	8%	13%	0.162	0.511	1,509	1,223	117%	14%	11%	9%	\$852	\$405	\$1,345
PS-N	\$321	\$133	7%	13%	0.029	0.376	686	584	111%	9%	11%	8%	\$683	\$304	\$1,086
ATSI-C	\$291	\$110	6%	11%	0.172	0.392	1,233	925	120%	15%	9%	8%	\$531	\$275	\$826
DPL-S	\$305	\$122	6%	14%	0.049	0.364	413	343	113%	11%	11%	8%	\$307	\$142	\$483
33% Lower Shocks															
MAAC	\$277	\$67	3%	39%	0.033	0.116	1,100	1,600	102%	2%	25%	11%	\$7,257	\$4,915	\$10,003
EMAAC	\$291	\$77	4%	27%	0.027	0.143	952	1,158	102%	3%	21%	11%	\$4,086	\$2,678	\$5,675
SWMAAC	\$291	\$75	4%	20%	0.025	0.140	793	784	105%	5%	15%	7%	\$1,702	\$1,136	\$2,357
ATSI	\$277	\$67	4%	20%	0.023	0.107	782	756	105%	5%	15%	9%	\$1,481	\$1,038	\$1,985
PSEG	\$305	\$83	3%	16%	0.018	0.161	686	596	105%	5%	14%	7%	\$1,360	\$867	\$1,888
PEPCO	\$305	\$84	6%	16%	0.028	0.169	722	624	108%	7%	12%	9%	\$865	\$555	\$1,224
PS-N	\$321	\$92	4%	18%	0.020	0.181	329	302	105%	5%	13%	6%	\$693	\$425	\$983
ATSI-C	\$291	\$76	5%	14%	0.026	0.133	585	466	110%	8%	11%	8%	\$538	\$360	\$754
DPL-S	\$305	\$84	4%	17%	0.019	0.161	205	175	107%	6%	12%	7%	\$310	\$196	\$437

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

C. OPTIONS FOR IMPROVING PERFORMANCE IN LDAs

As discussed in Section V.B, we find that LDAs are susceptible to low reliability under the current VRR curve, particularly in LDAs that are highly import-dependent or that have Net CONE substantially above the parent Net CONE. We also find that the 1.5× Convex Tuned curve that we recommend at the system level performs better than the current curve as applied at the local level, but still falls short of performance and robustness objectives (although the 1.7× Convex Tuned and Right-Shifted Curves showed better performance).

To develop a VRR curve recommendation at the local level that is also consistent with our system-wide recommendations, we begin with the recommended 1.5× Convex Tuned curve from the system level, and then test a series of approaches to improving performance and protection against low-reliability events. In this Section, we rely primarily on a realistic stressed scenario, in which most LDAs have Net CONE at 5% above the parent level, but where the lowest-level LDAs have Net CONE at 20% above the parent level (and where administrative Net CONE is accurate in each location). We focus on performance results in these lowest-level LDAs because these areas are the most susceptible to reliability performance concerns.

First, we first test the level of reliability improvement under a number of different options for increasing the cap, right-shifting the curve, or right-stretching the curve, finding that increasing the price cap to 1.7× Net CONE is the most beneficial followed by right-stretching. Second, we test the impacts of combining these two approaches, testing alternative approaches to right-stretching the curve that are or are not proportional to LDA size and CETL. In this test, we find that right-stretching the curves to a minimum width of 25% of CETL provides substantial protection against reliability shortfalls in the most vulnerable, import-dependent LDAs without substantially increasing procurement costs in the less-vulnerable locations. Finally, in the last sub-section here, we report the performance of the 1.5× Convex Tuned curve after adopting both of these recommendations under both non-stress and stress scenarios, showing substantially improved performance and robustness.

1. Reducing Susceptibility to Low-Reliability Events

In this Section, we begin with the 1.5× Convex Curve that we recommend adopting at the system level, but test a series of options for improving its performance in the most import-dependent locations and protecting against low-reliability events. We, therefore, present performance results in a stress scenario for the 1.5× Convex Tuned curve as-is, and, after applying four different adjustments, comparing:

- **1.5× Convex Curve**, *i.e.*, the curve shape we are recommending for the system, but applied at the LDA level;
- **LDA Cap at 1.7×**, assuming the 1.5× Convex curve with no revisions at the system level, and increasing the cap to 1.7× Net CONE at the LDA level (but keeping all other price and quantity parameters unchanged);

- **Right-Shifting the Entire Curve**, with point “a” shifted from the quantity corresponding to 1-in-5 for system to the Reliability Requirement, and right-shifting all other quantity points by the same amount;
- **Doubling the Width** by keeping the cap quantity fixed at the quantity corresponding to 1-in-5 for system, but right-stretching the curve until the kink and foot quantities are both twice the original distance from the cap; and
- **Imposing a 1,500 Minimum Width** on the curve while keeping the quantity at the cap is fixed at the quantity corresponding to 1-in-5 for system, so that even in the smallest LDAs the quantity at the foot will be at least 1,500 MW higher than the quantity at the cap, with the quantity at the kink adjusting proportionately.

Table 22 shows simulated performance for each of these curve shapes. In all cases, we show results for the 5% / 20% higher Net CONE assumption, reporting results only for the most import-constrained LDAs in which we have assumed a 20% higher Net CONE. As the table shows, increasing the cap to 1.7× Net CONE and increasing the width of the VRR Curves each improve reliability. Based on these results and the protection it provides against under-estimates to Net CONE as discussed in Section VI.B.3, we recommend that PJM consider increasing the price cap in the LDAs to at least 1.7× Net CONE (even if not doing so on a system-wide basis). We also observe that right-stretching the local curves provides additional reliability and volatility-mitigating benefit, and so we examine refinements to these options in the following section.

Table 22
Performance of 1.5× Convex Curve with Adjustments to Improve Local Reliability
(Net CONE 5% Higher for Most LDAs; 20% Higher for PS-North, DPL-South, PepCo, and ATSI-C)

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req.	St. Dev.	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	(\$/MW-d)	(\$/MW-d)	(%)	(%)	(Ev/Yr)	(Ev/Yr)	(MW)	(MW)	(%)	(%)	(%)	(%)	(\$mil)	(\$mil)	(\$mil)
Convex Tuned, 1.5x Cap															
PEPCO	\$349	\$137	23%	35%	0.423	0.589	540	899	106%	10%	26%	22%	\$914	\$488	\$1,382
PS-N	\$366	\$149	22%	39%	0.067	0.245	237	429	104%	7%	28%	19%	\$757	\$356	\$1,154
ATSI-C	\$332	\$127	21%	31%	0.630	0.748	461	686	108%	11%	23%	21%	\$567	\$317	\$850
DPL-S	\$349	\$139	21%	35%	0.107	0.267	164	253	105%	8%	26%	20%	\$336	\$166	\$511
LDA Cap at 1.7x (System Cap at 1.5x)															
PEPCO	\$349	\$156	17%	29%	0.218	0.360	716	899	108%	10%	20%	16%	\$911	\$473	\$1,468
PS-N	\$366	\$171	17%	32%	0.045	0.196	326	429	105%	7%	22%	14%	\$757	\$348	\$1,263
ATSI-C	\$332	\$142	16%	26%	0.342	0.449	566	685	109%	11%	18%	16%	\$565	\$313	\$870
DPL-S	\$349	\$158	16%	30%	0.070	0.206	205	253	107%	8%	20%	16%	\$335	\$162	\$553
Double Width															
PEPCO	\$349	\$128	19%	38%	0.257	0.389	682	900	108%	10%	22%	18%	\$935	\$531	\$1,358
PS-N	\$366	\$136	16%	45%	0.043	0.182	343	430	105%	7%	21%	13%	\$776	\$410	\$1,147
ATSI-C	\$332	\$121	17%	34%	0.398	0.507	548	685	109%	11%	19%	17%	\$577	\$324	\$844
DPL-S	\$349	\$128	16%	40%	0.071	0.199	209	253	107%	8%	20%	16%	\$344	\$189	\$509
1,500MW Min Width															
PEPCO	\$349	\$131	18%	39%	0.239	0.405	700	898	108%	10%	21%	17%	\$929	\$494	\$1,389
PS-N	\$366	\$130	10%	49%	0.026	0.201	456	431	107%	7%	14%	9%	\$781	\$413	\$1,153
ATSI-C	\$332	\$116	13%	38%	0.222	0.338	658	685	111%	11%	15%	14%	\$586	\$337	\$854
DPL-S	\$349	\$102	3%	58%	0.007	0.168	438	255	114%	8%	4%	3%	\$368	\$234	\$514
Point "a" Right-Shifted to Reliability Requirement															
PEPCO	\$349	\$137	23%	35%	0.301	0.439	635	899	107%	10%	23%	19%	\$923	\$488	\$1,398
PS-N	\$366	\$149	22%	39%	0.050	0.197	305	429	105%	7%	22%	15%	\$764	\$357	\$1,168
ATSI-C	\$332	\$127	21%	31%	0.455	0.565	521	686	109%	11%	21%	18%	\$571	\$317	\$859
DPL-S	\$349	\$139	21%	35%	0.079	0.213	196	253	106%	8%	21%	16%	\$339	\$167	\$517

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

2. Mitigating the Impacts of CETL Volatility and Import Dependence

In the prior sections, we discussed two related concerns: (1) that all LDAs are subject to price spikes, of which volatility in CETL is a substantial driver; and (2) the most import-dependent LDAs are susceptible to a greater frequency of low reliability events. We evaluate here options for mitigating against both concerns, by combining a higher LDA price cap at 1.7× Net CONE with various options for right-stretching the local curves. Under each case, we adopt the same modeling assumptions described in the prior section, and again report results only for the most import-constrained LDAs where we assume Net CONE at 20% above the parent value.

We evaluate two of the same right-stretching options evaluated in the prior section (doubling the width, and imposing a 1,500 MW minimum width) combined with a higher price cap. We also test the impacts of imposing a minimum width at 25% or 50% of CETL, in order to tie the level of right-

stretching more closely with both LDA size (which approximately scales with CETL) as well as the level of import dependence. The resulting curve widths under each case are summarized in Table 23, along with a comparison to the current VRR curve width as well as the 2016/17 CETL and Reliability Requirement parameters in each location.

Table 23
VRR Curve Width under 1.5× Convex Curve, and if Stretched by Varying Amounts

LDA	2016/17 Parameters				Absolute Width					Width Normalized by Reliability Requirement				
	RR	CETL	VRR Curve Width	VRR Curve Width	1.5 Convex	Double Width	1,500 MW Min	Min Width 25% of CETL	Min Width 50% of CETL	1.5 Convex	Double Width	1,500 MW Min	Min Width 25% of CETL	Min Width 50% of CETL
	(MW)	(MW)	(MW)	(%)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)	(%)
MAAC	72,299	6,155	5,003	6.9%	5,639	11,279	5,639	5,639	5,639	7.8%	15.6%	7.8%	7.8%	7.8%
EMAAC	39,694	8,286	2,747	6.9%	3,096	6,192	3,096	3,096	4,143	7.8%	15.6%	7.8%	7.8%	10.4%
SWMAAC	17,316	7,140	1,198	6.9%	1,351	2,701	1,500	1,785	3,570	7.8%	15.6%	8.7%	10.3%	20.6%
ATSI	16,255	7,256	1,125	6.9%	1,268	2,536	1,500	1,814	3,628	7.8%	15.6%	9.2%	11.2%	22.3%
PSEG	12,870	6,241	891	6.9%	1,004	2,008	1,500	1,560	3,121	7.8%	15.6%	11.7%	12.1%	24.2%
PEPCO	9,012	5,733	624	6.9%	703	1,406	1,500	1,433	2,867	7.8%	15.6%	16.6%	15.9%	31.8%
PSEG-N	6,440	2,733	446	6.9%	502	1,005	1,500	683	1,367	7.8%	15.6%	23.3%	10.6%	21.2%
ATSI-C	6,164	5,093	427	6.9%	481	962	1,500	1,273	2,546	7.8%	15.6%	24.3%	20.7%	41.3%
DPL-S	3,160	1,836	219	6.9%	246	493	1,500	459	918	7.8%	15.6%	47.5%	14.5%	29.1%

Note:

Curve widths represent the difference between point “a” and point “c” on the VRR Curve, relative to 2016/17 parameters.

Table 24 summarizes curve performance under each of these options, combined with a higher LDA price cap at 1.7× Net CONE. As expected, the widest-stretched curves provide the greatest reliability and price volatility benefits. However, these benefits come at the expense of increasing the average quantity of supply, which increases average customer costs in that LDA by a proportional amount.⁷³ Increasing the width of the curves in proportion to CETL appears to be the most attractive of these options, as the consequence is to provide the most reliability benefit in the locations where the additional local supply is needed most. While increasing the width to a bit more than 50% of CETL would be necessary to fully meet the 0.04 LOLE standard in all of these LDAs with Net CONE 20% higher than parent, we recommend the more modest 25% minimum width because this adjustment achieves most of the reliability benefits at only about 30% of the cost compared to the 50% higher case.

⁷³ Note that aggregate system costs increase only marginally because increasing the quantity procured in an LDA does not increase the total system procurement but only shifts the location of that procurement from a higher-level to lower-level LDA, resulting in a small total system cost increase equal to the quantity of supply shifted times the Net CONE differential between the two locations. However, *customer costs* within that LDA *do* increase relatively proportionally to any right-shift in demand curves for that sub-region, because the share of procurement costs borne by local customer’s increases.

Table 24
Performance of 1.5× Convex Curve with LDA Cap increased to 1.7×
and LDA Curve Width Right-Stretched by Varying Amounts
(Net CONE 5% Higher for Most LDAs; 20% Higher for PS-North, DPL-South, PepCo, and ATSI-C)

	Price				Reliability				Procurement Costs						
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req. (MW)	St. Dev. (MW)	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	(\$/MW-d)	(\$/MW-d)	(%)	(%)	(Ev/Yr)	(Ev/Yr)	(MW)	(MW)	(%)	(%)	(%)	(%)	(\$mil)	(\$mil)	(\$mil)
LDA Cap at 1.7x Net CONE															
PEPCO	\$349	\$156	17%	29%	0.218	0.360	716	899	108%	10%	20%	16%	\$911	\$473	\$1,468
PS-N	\$366	\$171	17%	32%	0.045	0.196	326	429	105%	7%	22%	14%	\$757	\$348	\$1,263
ATSI-C	\$332	\$142	16%	26%	0.342	0.449	566	685	109%	11%	18%	16%	\$565	\$313	\$870
DPL-S	\$349	\$158	16%	30%	0.070	0.206	205	253	107%	8%	20%	16%	\$335	\$162	\$553
LDA Cap at 1.7x Net CONE, Double Width of Curves															
PEPCO	\$349	\$147	14%	32%	0.135	0.252	853	899	110%	10%	16%	14%	\$932	\$510	\$1,450
PS-N	\$366	\$156	11%	38%	0.029	0.154	426	430	107%	7%	15%	9%	\$774	\$391	\$1,236
ATSI-C	\$332	\$135	13%	30%	0.206	0.307	662	685	111%	11%	15%	13%	\$576	\$320	\$871
DPL-S	\$349	\$146	12%	35%	0.044	0.160	254	253	108%	8%	15%	11%	\$343	\$179	\$542
LDA Cap at 1.7x Net CONE, 1,500MW Min Width of Curves															
PEPCO	\$349	\$150	14%	33%	0.125	0.266	871	897	110%	10%	16%	13%	\$926	\$483	\$1,479
PS-N	\$366	\$150	8%	44%	0.018	0.166	539	430	108%	7%	9%	6%	\$782	\$396	\$1,241
ATSI-C	\$332	\$131	11%	33%	0.109	0.215	781	684	113%	11%	13%	11%	\$584	\$329	\$886
DPL-S	\$349	\$118	2%	55%	0.004	0.142	486	254	115%	8%	3%	2%	\$367	\$225	\$547
LDA Cap at 1.7x Net CONE, Min Width of Curves at 25% of CETL															
PEPCO	\$349	\$150	14%	32%	0.132	0.270	857	897	110%	10%	16%	14%	\$925	\$485	\$1,476
PS-N	\$366	\$167	15%	34%	0.039	0.186	363	429	106%	7%	19%	11%	\$761	\$356	\$1,261
ATSI-C	\$332	\$133	12%	32%	0.143	0.248	730	684	112%	11%	13%	12%	\$580	\$327	\$880
DPL-S	\$349	\$152	13%	33%	0.047	0.185	247	253	108%	8%	16%	12%	\$339	\$168	\$553
LDA Cap at 1.7x Net CONE, Min Width of Curves at 50% of CETL															
PEPCO	\$349	\$137	8%	41%	0.046	0.174	1,150	897	113%	10%	10%	8%	\$962	\$522	\$1,486
PS-N	\$366	\$150	9%	43%	0.021	0.161	503	430	108%	7%	11%	7%	\$783	\$402	\$1,230
ATSI-C	\$332	\$118	6%	41%	0.033	0.129	1,008	684	116%	11%	8%	6%	\$611	\$359	\$897
DPL-S	\$349	\$136	6%	45%	0.018	0.153	347	253	111%	8%	8%	5%	\$352	\$191	\$552

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

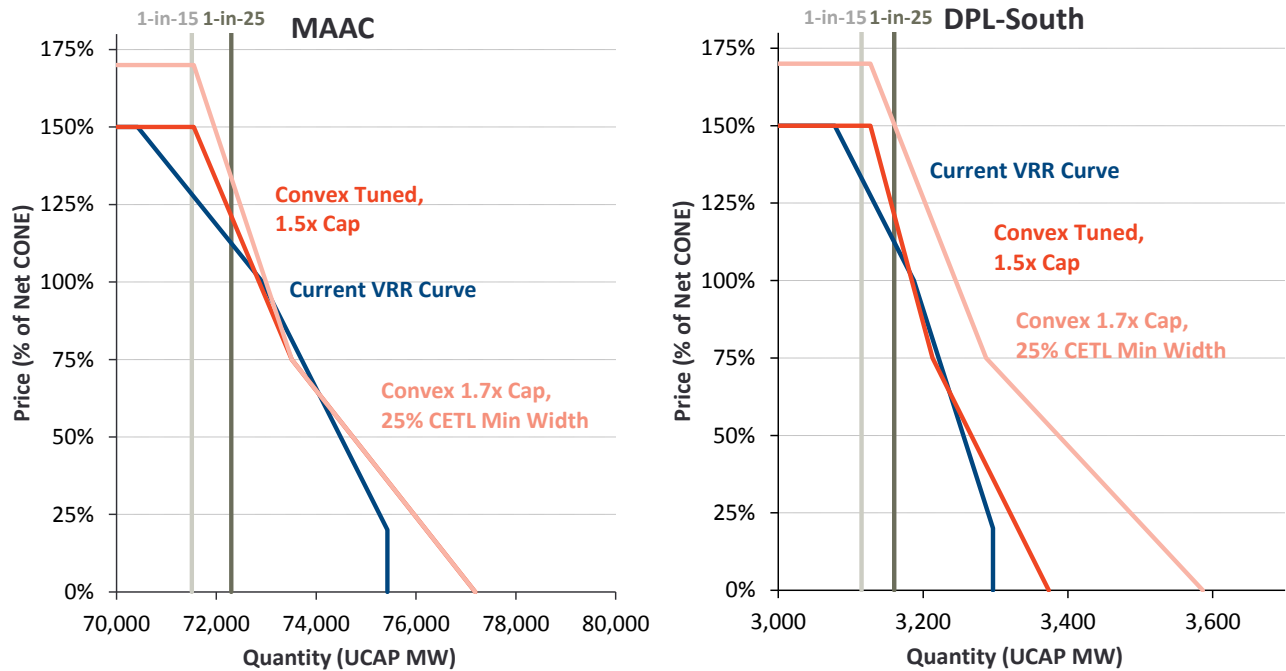
3. Performance after Recommended Adjustments

We provide here additional results illustrating the performance of the LDA VRR curves if adopting each of the recommended adjustments. The resulting curves are illustrated in Figure 30 for the largest LDA MAAC and the smallest LDA DPL-South, compared to the current VRR Curve. Parameters for the rest of the LDAs are summarized in Table 25. These adjusted LDA curves reflect the following progressive refinements: (a) start with the 1.5× Convex Tuned curve, adapted to the LDA level; (b) increase the price cap to 1.7× Net CONE for the LDAs, without adjusting the other curve parameters; and (c) right-stretch the curves to a minimum width of 25% of the LDA CETL value.

As shown in Table 26, the adjusted curves show substantially improved reliability performance compared to the current VRR curve, with all LDAs achieving the reliability objective if Net CONE is at a typical level of approximately 5% above the parent LDA level. Under a more stressed case

where the most import-constrained LDAs have Net CONE 20% above parent, only one of these LDAs continues to meet the reliability objective but the reliability impacts of falling short are substantially mitigated, with the lowest-reliability LDA having LOLE 70% lower than under the current VRR curve in the same sensitivity case. Finally, the reliability impacts are substantially mitigated in the presence of under-estimates to Net CONE, with LOLE in the most-affected LDA dropping by 80% compared to the same sensitivity case under the current VRR curve.

Figure 30
PJM’s Current VRR Curve Compared to Recommended Local Curve
 (LDA Price Cap increased to 1.7× Net CONE, with Minimum Width at 25% of CETL)



Sources and Notes:

Current VRR Curve reflects the locational VRR curve parameters for MAAC and DPL-South in the 2016/2017 PJM Planning Parameters. See PJM (2013a.)

Convex Tuned, 1.5× Cap shows our recommended curve for system applied to the MAAC and DPL-South.

Convex 1.7× Cap, 25% CETL Min Width modifies the Convex Tuned 1.5× CAP by raising the cap to 1.7× Net CONE, and stretching points “b” and “c” such that the width of the curve (“the distance between “a” and “c”) is at least 25% of CETL.

Table 25
Resulting Curve Width by LDA, if Applying a Minimum Width of 25% CETL

LDA	Absolute Curve Width			Curve Width (% of RR)		
	Current	Convex	Min Width	Current	Convex	Min Width
	VRR	Tuned	25% of CETL	VRR	Tuned	25% of CETL
	(MW)	(MW)	(MW)	(%)	(%)	(%)
MAAC	5,003	5,639	5,639	6.9%	7.8%	7.8%
EMAAC	2,747	3,096	3,096	6.9%	7.8%	7.8%
SWMAAC	1,198	1,351	1,785	6.9%	7.8%	10.3%
ATSI	1,125	1,268	1,814	6.9%	7.8%	11.2%
PSEG	891	1,004	1,560	6.9%	7.8%	12.1%
PEPCO	624	703	1,433	6.9%	7.8%	15.9%
PSEG-N	446	502	683	6.9%	7.8%	10.6%
ATSI-Cleveland	427	481	1,273	6.9%	7.8%	20.7%
DPL-S	219	246	459	6.9%	7.8%	14.5%

Sources and Notes:

“Width” is defined as the horizontal distance from point “a” at the cap to “c” at the bottom of the curve, expressed in in UCAP terms and as a percentage of the Reliability Requirement.

Table 26
Performance of 1.5× Convex Curve with LDA Cap at 1.7× and Minimum Width of 25% CETL

	Price				Reliability				Procurement Costs						
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req. (MW)	St. Dev. (MW)	Average Quantity as % of Rel. Req. (%)	St. Dev. as % of Rel. Req. (%)	Freq. Below Rel. Req. (%)	Freq. Below 1-in-15 (%)	Average (\$mil)	Average of Bottom 20% (\$mil)	Average of Top 20% (\$mil)
	(\$/MW-d)	(\$/MW-d)	(%)	(%)	(Ev/Yr)	(Ev/Yr)	(MW)	(MW)	(%)	(%)	(%)	(%)	(\$mil)	(\$mil)	(\$mil)
Net CONE 5% Higher than Parent															
MAAC	\$277	\$103	9%	24%	0.030	0.116	2,113	2,301	103%	3%	17%	9%	\$7,211	\$3,997	\$11,589
EMAAC	\$291	\$115	9%	19%	0.020	0.137	1,829	1,691	105%	4%	14%	8%	\$4,054	\$2,168	\$6,583
SWMAAC	\$291	\$112	6%	15%	0.020	0.136	1,531	1,154	109%	7%	7%	5%	\$1,691	\$922	\$2,720
ATSI	\$277	\$98	6%	15%	0.018	0.104	1,486	1,120	109%	7%	8%	6%	\$1,481	\$879	\$2,225
PSEG	\$305	\$122	4%	13%	0.010	0.147	1,317	883	110%	7%	6%	4%	\$1,354	\$697	\$2,184
PEPCO	\$305	\$119	5%	12%	0.017	0.154	1,422	919	116%	10%	6%	4%	\$859	\$452	\$1,394
PS-N	\$321	\$133	5%	13%	0.012	0.159	637	442	110%	7%	7%	4%	\$689	\$340	\$1,147
ATSI-C	\$291	\$105	4%	12%	0.014	0.118	1,169	694	119%	11%	4%	4%	\$539	\$304	\$833
DPL-S	\$305	\$122	4%	14%	0.012	0.148	391	258	112%	8%	5%	3%	\$309	\$159	\$505
Net CONE 5% Higher than Parent, 20% in Smallest LDAs															
MAAC	\$277	\$104	9%	24%	0.030	0.117	2,115	2,308	103%	3%	17%	9%	\$7,342	\$4,113	\$11,678
EMAAC	\$291	\$116	9%	19%	0.020	0.137	1,841	1,695	105%	4%	14%	8%	\$4,139	\$2,215	\$6,658
SWMAAC	\$291	\$112	6%	15%	0.021	0.138	1,529	1,158	109%	7%	8%	5%	\$1,736	\$955	\$2,750
ATSI	\$277	\$98	6%	15%	0.018	0.104	1,488	1,120	109%	7%	8%	6%	\$1,505	\$900	\$2,241
PSEG	\$305	\$123	4%	13%	0.011	0.148	1,318	884	110%	7%	6%	4%	\$1,418	\$714	\$2,255
PEPCO	\$349	\$150	14%	32%	0.132	0.270	857	897	110%	10%	16%	14%	\$925	\$485	\$1,476
PS-N	\$366	\$167	15%	34%	0.039	0.186	363	429	106%	7%	19%	11%	\$761	\$356	\$1,261
ATSI-C	\$332	\$133	12%	32%	0.143	0.248	730	684	112%	11%	13%	12%	\$580	\$327	\$880
DPL-S	\$349	\$152	13%	33%	0.047	0.185	247	253	108%	8%	16%	12%	\$339	\$168	\$553
Net CONE 5% Higher than Parent with 20% Under-Estimate															
MAAC	\$277	\$78	20%	31%	0.069	0.279	1,177	2,460	102%	3%	30%	20%	\$7,162	\$4,375	\$10,201
EMAAC	\$291	\$88	20%	30%	0.049	0.328	983	1,745	102%	4%	29%	19%	\$4,031	\$2,376	\$5,855
SWMAAC	\$291	\$85	14%	22%	0.066	0.345	1,055	1,175	106%	7%	19%	12%	\$1,683	\$1,006	\$2,407
ATSI	\$277	\$73	13%	22%	0.047	0.257	1,023	1,126	106%	7%	17%	13%	\$1,469	\$947	\$1,972
PSEG	\$305	\$93	12%	19%	0.028	0.356	962	893	108%	7%	15%	11%	\$1,345	\$770	\$1,936
PEPCO	\$305	\$89	10%	19%	0.089	0.434	1,033	927	112%	10%	13%	10%	\$858	\$504	\$1,252
PS-N	\$321	\$101	12%	20%	0.032	0.388	430	445	107%	7%	16%	10%	\$686	\$378	\$1,002
ATSI-C	\$291	\$78	9%	17%	0.076	0.333	871	693	114%	11%	10%	9%	\$536	\$334	\$761
DPL-S	\$305	\$93	9%	18%	0.030	0.358	299	258	110%	8%	12%	8%	\$308	\$173	\$454

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

D. RECOMMENDATIONS FOR LOCATIONAL CURVES

Similar to the system, the local VRR curves have maintained reliability to date. However, the forward-looking concerns we identified for the system also exist for modeled LDAs, but to a greater extent due to the LDAs' susceptibility to changes in CETL, their smaller size relative to likely shocks, and the challenge of attracting investments in small LDAs where the local Net CONE is higher than in the parent zone. Our simulations demonstrate these risks and show that the existing VRR curves would not likely achieve the 1-in-25 conditional target, 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. **Adopt the changes we recommended for the system VRR curve.** We find that right-shifting point “a” and stretching the curve into a convex shape offer improvements over the current VRR curve and are a good starting point for the incremental refinements defined below.
2. **Increase the LDA price cap to 1.7× Net CONE.** We find that a higher cap substantially improves simulated 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. This change would also provide substantial protection against the risks of under-procurement in stress scenarios.
3. **Impose a minimum curve width equal to 25% of CETL.** We find that raising the LDA price cap to 1.7× Net CONE would not by itself achieve the local reliability objective in a realistic stress scenario with Net CONE in an LDA is substantially above the parent level, with even larger gaps under a sensitivity scenario with under-estimated Net CONE. 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.

In addition, we have four other recommendations affecting local VRR curves, although they are not strictly about the VRR curve shape and thus are not directly within the scope of the review prescribed in PJM’s tariff:

1. **Consider defining local reliability objectives in terms of normalized unserved energy.** As discussed in Section VI.A.2, 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.** As discussed in Section VI.A.4, 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, we see the potential for different types of constraints emerging 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.
3. **Evaluate options for increasing stability of Capacity Emergency Transfer Limits (CETL).** As discussed in Section VI.A.4, 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 would need to continue to be reflected as changes in CETL, but reducing uncertainty would provide substantial benefits in reducing price volatility. We have provided more detailed suggestions on 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 added 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 also 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).

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List of Acronyms

AECO	Atlantic City Electric Company
AEP	American Electric Power
APS	Allegheny Power System
A/S	Ancillary Service
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
Dayton	Dayton Power and Light Company, aka DAY
DEOK	Duke Energy Ohio/Kentucky
DLCO	Duquesne Lighting Company, aka DUQ or DQE or DLCO
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
FRR	Fixed Resource Requirement
H-W	Handy-Whitman Index
IA	Incremental Auction

IMM	Independent Market Monitor
IRM	Installed Reserve Margin
ISO	Independent System Operator
ISO-NE	ISO New England
JCPL	Jersey Central Power and Light Company
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
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
PPI	Producer Price Index
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
QCEW	Quarterly Census of Employment and Wages
RECO	Rockland Electric Company
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization

STRPT	Short-Term Resource Procurement Target
SWMAAC	Southwestern Mid-Atlantic Area Council
UCAP	Unforced Capacity
VOM	Variable Operations and Maintenance
VRR	Variable Resource Requirement
WMAAC	Western Mid-Atlantic Area Council

Appendix A: Magnitude and Implementation of Monte Carlo Shocks

In this appendix we provide additional detail on our approach to estimating and implementing a realistic magnitude of shocks into our Monte Carlo simulation modeling, including shocks to: (1) supply offer quantity; (2) load forecast and Reliability Requirement; (3) administrative net CONE; and (4) CETL. A summary of these shocks and the combined supply minus demand shocks in each location is included in Section IV.C above.

A1. SHOCKS TO SUPPLY OFFER QUANTITY

We estimate gross supply shocks based on the range of actual total supply offer quantities in historical BRAs over delivery years 2009/10 to 2016/17, based on offer data provided by PJM. Table 27 summarizes the total supply offered by LDA, as well as several series of historical shocks calculated in differed ways, based the distributions of total supply offers, year-to-year changes in supply offers, and differences in supply offers relative to a linear time trend. We determine reasonable supply shock magnitudes based on the historical shocks as an exponential function of LDA size, resulting in the final supply shock values shown in column 7 of Table 27.

Table 27
Shocks to Supply Offers

	Total Supply Offered by Delivery Year								Standard Deviation of Historical "Shocks"						Simulated Shock Std. Dev	
	2009	2010	2011	2012	2013	2014	2015	2016	Total Offers	Annual Change in Offer	Diff. from Trend	Total Offers	Annual Change in Offer	Diff. from Trend		
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)		
									[1]	[2]	[3]	[4]	[5]	[6]	[7]	
RTO Including Subzones																
Total Offered (No Adjustments)	133,551	133,093	137,720	145,373	160,898	160,486	178,588	184,380	20,040	7,229	4,816	13%	5%	3%	4,054	
Adjust for Expansions Only [A]	133,551	133,093	137,057	144,333	146,479	146,646	163,802	165,729	12,594	6,105	3,983	9%	4%	3%		
Adjust for FRR Only [B]	133,551	133,093	137,720	145,373	160,898	160,486	163,231	169,023	14,604	5,518	3,878	10%	4%	3%		
Adjust for Expansions and FRR [C]	133,551	133,093	137,057	144,333	146,479	146,646	158,769	160,696	10,537	4,452	2,697	7%	3%	2%		
Parent LDAs Including Sub-LDAs																
MAAC	63,443	63,919	65,582	68,283	68,338	70,885	74,261	71,608	3,842	2,069	1,229	6%	3%	2%	2,767	
EMAAC	31,684	31,218	32,034	32,983	33,007	34,520	37,226	34,140	1,939	1,829	1,102	6%	5%	3%	1,591	
SWMAAC	10,312	10,928	11,651	12,396	11,768	12,458	12,722	12,386	843	562	409	7%	5%	3%	644	
ATSI	n/a	n/a	n/a	n/a	13,335	12,679	11,777	12,791	646	1,043	557	5%	8%	4%	663	
PSEG	6,957	7,220	7,403	7,431	8,033	8,184	8,964	6,784	725	987	657	10%	13%	9%	363	
Average LDA Shock									1,599	1,298	791	7%	7%	4%		
Smallest LDAs																
PEPCO	5,064	5,498	5,670	5,382	5,289	5,875	6,235	6,126	412	325	234	7%	6%	4%	328	
PS-North	3,767	3,871	4,010	3,420	4,173	4,170	4,931	4,182	436	586	338	11%	14%	8%	226	
ATSI-Cleveland	n/a	n/a	n/a	n/a	2,232	2,341	1,657	2,874	499	956	473	22%	42%	21%	157	
DPL-South	1,587	1,546	1,486	1,499	1,612	1,600	1,768	1,764	108	84	70	7%	5%	4%	97	
Average LDA Shock									364	488	279	12%	17%	9%		

Sources and Notes:

- [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 subtracted from Rest of RTO Supply in 2015/16. Supply from FRR is assumed to be equal to the decrease in the FRR obligation between 2014/14 and 2015/16.
- [C] The adjustments from [A] and [B] are combined. For the FRR, adjustment, the portion of the decrease in FRR obligation due to DEOK is 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] Column [1] divided by average total historical supply offer.
- [5] Column [2] divided by average total historical supply offer.
- [6] Column [3] divided by average total historical supply offer.
- [7] Exponential formula of column [6] and average total historical supply offer

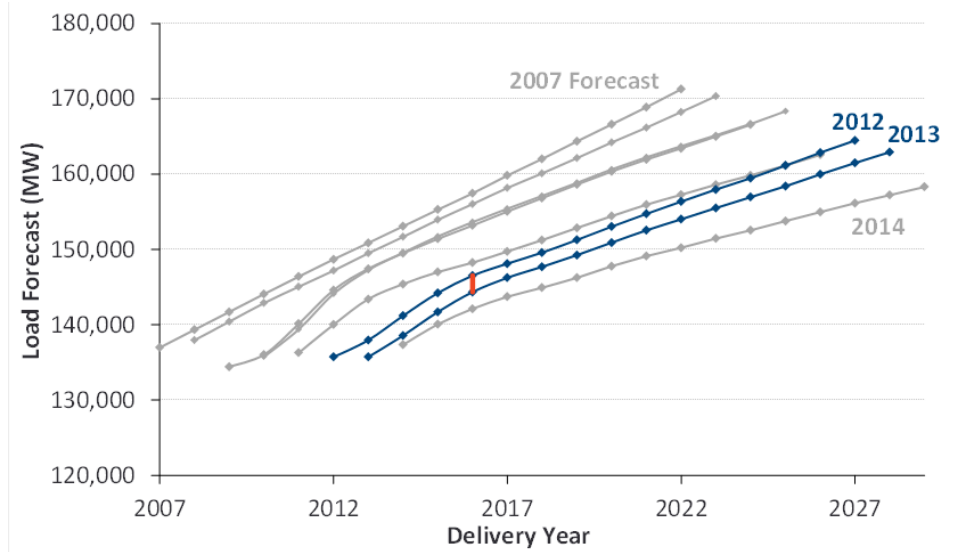
A2. SHOCKS TO LOAD FORECAST AND RELIABILITY REQUIREMENT

We estimate demand shocks in two components: (1) shocks to load forecast, and (2) shocks to the Reliability Requirement expressed as a percentage of system or local peak load. We estimate the shocks to system load forecast as a normally-distributed distribution around the expected value, based on historical year-to-year changes in annual load forecasts. We calculate historical shocks to the system load forecast as the delta between four- and three-year ahead forecasts for the same delivery year, as illustrated in Figure 31.⁷⁴ The resulting standard deviation of the system shocks is 0.8% of the expected RTO system-wide peak load. Note that this calculated shock measures

⁷⁴ See PJM Load Forecasts PJM (2007 – 2014).

only the *uncertainty* in year-to-year changes in the load forecast, but excludes any *bias* in the load forecast.

Figure 31
RTO Load Forecast

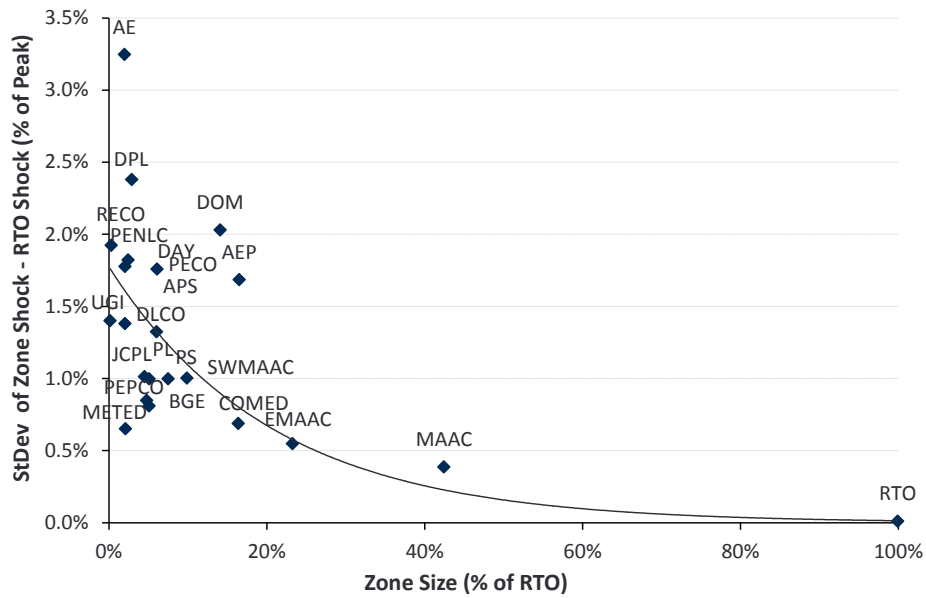


Sources and Notes:

Load forecasts as reported in PJM Load Forecast Reports. See PJM (2007 – 2014).

To develop peak load shocks for the LDAs, we use a similar method but account for correlations between the shocks to the LDA peak load, the system peak load, and the parent LDA’s peak load. In particular, we generate shocks for the smallest LDAs as the system shock plus an independently-generated shock that depends on LDA size, as shown in Figure 32. Bigger LDAs aggregate small LDA shocks and an appropriately-sized “rest of” LDA shock. The “Rest of” LDA includes all the zones within this LDA that are not part of a sub-LDA. Table 28 shows the aggregate load forecast shocks for the RTO and all LDAs.

Figure 32
LDA Load Forecast Error Shock
 (Zone or LDA Shock minus RTO Shock)



Sources and Notes:

Standard Deviation of Zone Shock minus RTO shock calculated based on historic PJM Load Forecast Reports. See PJM (2007 – 2014.)

Zone Size calculated based on 2016/17 Reliability Requirement. See PJM (2013a.)

Table 28
Aggregate RTO and LDA Load Forecast Shocks

Location	Base Assumptions 2016/17		Simulated Shock Standard Deviation			Historical Load Forecast Shocks (%)
	Peak Load (MW)	Total Shocks (MW)	RTO-Correlated Shock (%)	Shock on Top of RTO (%)	Total Shock (%)	
RTO	152,383	1,237	0.8%	0.0%	0.8%	0.8%
MAAC	61,080	604	0.8%	0.6%	1.0%	1.0%
EMAAC	33,299	373	0.8%	0.8%	1.1%	1.3%
SWMAAC	14,088	187	0.8%	1.1%	1.3%	1.2%
ATSI	13,295	183	0.8%	1.1%	1.4%	1.3%
PSEG	10,600	158	0.8%	1.3%	1.5%	1.3%
PEPCO	6,800	114	0.8%	1.5%	1.7%	1.0%
PS-N	5,141	87	0.8%	1.5%	1.7%	n/a
ATSI-C	4,562	77	0.8%	1.5%	1.7%	n/a
DPL-S	2,439	46	0.8%	1.7%	1.9%	n/a

Sources and Notes:

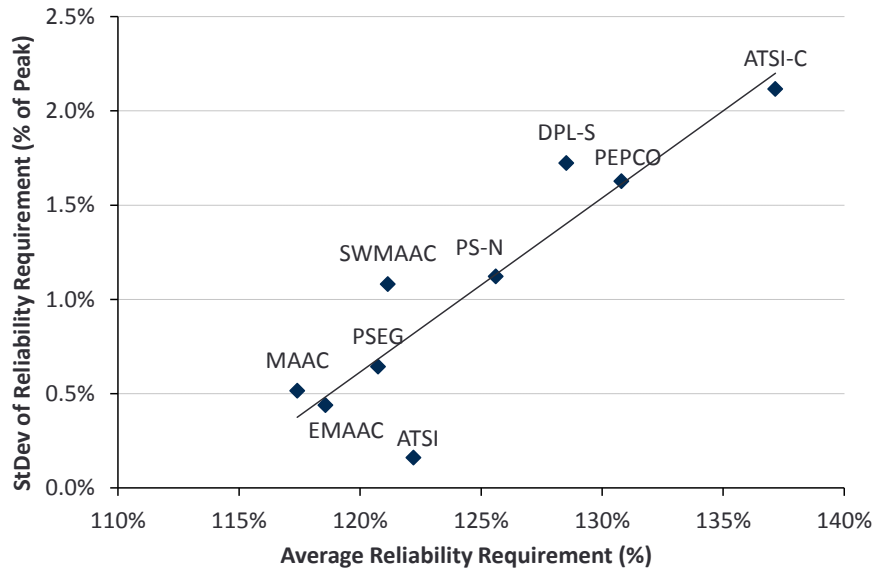
Peak Load from PJM 2016/17 Planning Parameters, see PJM (2013a.)

RTO-Correlated Shock and Shock on top of RTO are treated as independent random variables.

We calculate the total Reliability Requirement shock as equal to the load forecast shock plus an independent shock to the Reliability Requirement itself (when expressed as a percentage of peak load). For the RTO, we estimate a standard deviation of 0.4% in the Reliability Requirement

based on historical planning parameters.⁷⁵ For the LDAs, the standard deviation of the Reliability Requirement increases with its percentage of peak load, as shown Figure 33. Table 29 below shows the total Reliability Requirement shocks for RTO and the LDAs, including shocks to both load forecast and the Reliability Requirement as a percent of peak load.

Figure 33
Shocks to LDA Reliability Requirement
 (Expressed as % of Peak Load)



Sources and Notes:

LDA Reliability Requirement and Peak Load from Planning Parameters, PJM (2007 – 2013a).

Table 29
RTO and LDA Reliability Requirement Shocks

Location	2016/17		Simulation Shock Standard Deviations			Historical Reliability Requirement StDev (% of Peak)
	Reliability Requirement		Reliability Requirement	Load Forecast	Total Load Forecast + RR	
	(MW)	(% of Peak)	(% of Peak)	(MW)	(MW)	
RTO	166,128	109%	0.4%	1,237	1,499	0.4%
MAAC	72,299	118%	0.4%	604	794	0.5%
EMAAC	39,694	119%	0.5%	373	492	0.4%
SWMAAC	17,316	123%	0.7%	187	279	1.1%
ATSI	16,255	122%	0.8%	183	259	0.2%
PS	12,870	121%	0.7%	158	215	0.6%
PEPCO	9,012	133%	1.6%	114	220	1.6%
PS NORTH	6,440	125%	1.1%	87	131	1.1%
ATSI-Cleveland	6,164	135%	2.2%	77	164	2.1%
DPL SOUTH	3,160	130%	1.4%	46	76	1.7%

Sources and Notes:

2016/17 Reliability Requirement and Peak Load taken from PJM Planning Parameters. See PJM (2013a.)

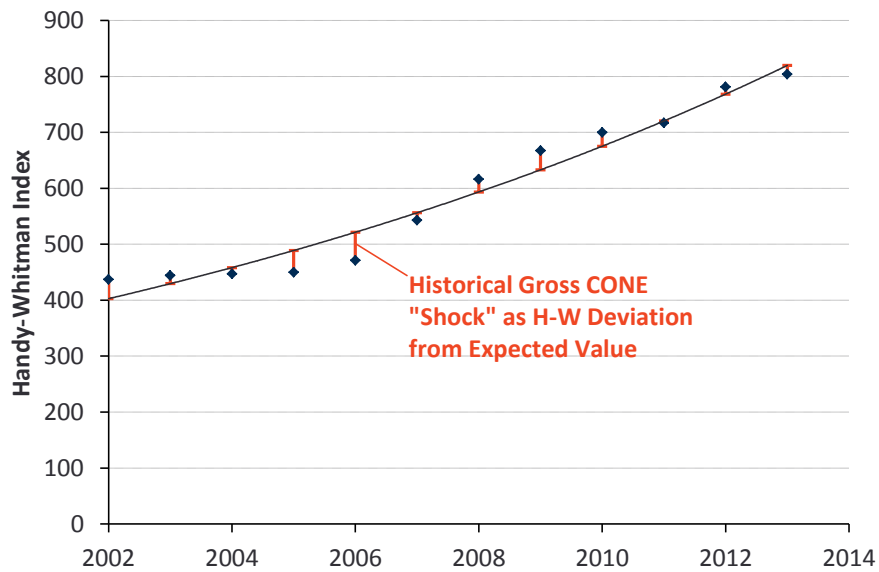
Simulation Shocks represent the parameters used in modeling.

⁷⁵ See PJM (2007 – 2013a.)

A3. SHOCKS TO ADMINISTRATIVE NET CONE

We develop Net CONE shocks as the sum of shocks to Gross CONE and a 3-year average E&AS shock. We model Gross CONE shocks of 5.4% based on deviations in the Handy-Whitman Index away from a long-term trend, as illustrated in Figure 34. For the E&AS shocks, we find the deviation of administrative E&AS estimates in each year from a fitted trend over 2002-2013. The standard deviation of these one-year historical E&AS estimates around the expected value is 38%, as summarized in Figure 35, which compares the one-year E&AS shocks relative to a normal distribution.

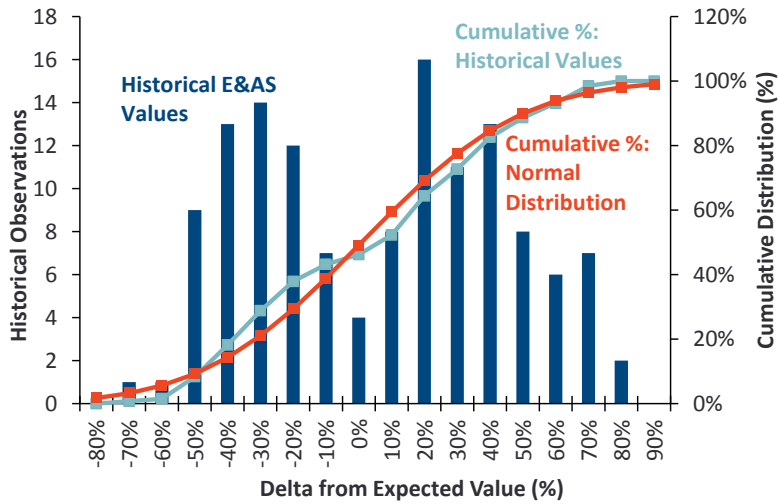
Figure 34
Handy-Whitman Index



Sources and Notes:

Based on the Handy-Whitman index issued in July of each year, see Whitman (2014).

Figure 35
One-Year E&AS Shocks



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 22% standard deviation in the three-year average E&AS offset, compared to a 38% standard deviation in the one-year E&AS offset. The resulting standard deviation in administrative Net CONE combines the shocks in both Gross CONE and E&AS as summarized in Table 30, resulting in a an 8% standard deviation in administrative Net CONE for RTO under our base case assumptions.

Table 30
Shocks to Administrative Net CONE

LDA	Base Assumptions from 2016/2017				Standard Deviation of Shock Components				Historical Shocks to Net CONE (%)
	Expected Gross CONE (\$/MW-d)	Expected E&AS (\$/MW-d)	Expected Net CONE (\$/MW-d)	Shocks to Net CONE (\$/MW-d)	Gross CONE (%)	One-Year E&AS (%)	Three-Year E&AS (%)	Net CONE (%)	
RTO	\$405	\$74	\$331	\$26	5.4%	38.4%	22.1%	8.0%	5.5%
ATSI	\$405	\$43	\$363	\$23	5.4%	38.4%	22.1%	6.4%	1.1%
ATSI-C	\$405	\$43	\$363	\$23	5.4%	38.4%	22.1%	6.4%	1.1%
MAAC	\$413	\$136	\$277	\$36	5.4%	38.4%	22.1%	13.1%	18.8%
EMAAC	\$443	\$113	\$330	\$33	5.4%	38.4%	22.1%	10.1%	9.8%
SWMAAC	\$413	\$136	\$277	\$36	5.4%	38.4%	22.1%	13.1%	12.8%
PSEG	\$443	\$113	\$330	\$33	5.4%	38.4%	22.1%	10.1%	3.0%
DPL-S	\$443	\$113	\$330	\$33	5.4%	38.4%	22.1%	10.1%	5.2%
PS-N	\$443	\$113	\$330	\$33	5.4%	38.4%	22.1%	10.1%	3.0%
PEPCO	\$413	\$136	\$277	\$36	5.4%	38.4%	22.1%	13.1%	4.6%

Sources and Notes:

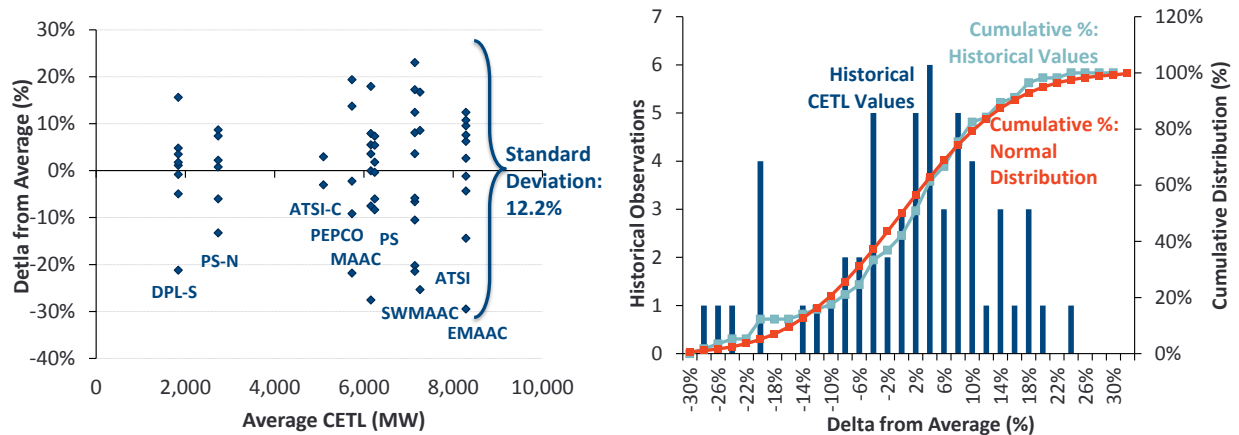
Expected Gross CONE, E&AS, and Net CONE consistent with 2016/17 Planning Parameters, see PJM (2013a.)

Historical shocks expressed as average of deviations from “trend” in Net CONE, although most LDAs have few data points.

A4. SHOCKS TO CAPACITY EMERGENCY TRANSFER LIMIT

We find that shocks are proportional to absolute CETL size but are relatively constant as a percent of CETL, as summarized in Figure 36. We estimate a 12.2% standard deviation on average across all locations in all years. We implement this 12.2% standard deviation using a normal distribution around the 2016/17 CETL value for each location as summarized in Table 31.

Figure 36
Historical CETL as Delta from Average



Sources and Notes:

Historical CETL value from PJM Planning Parameters. See PJM (2009a, 2009b, 2009, 2010, 2011, 2012, 2013a.)

Table 31
Historical and Simulation CETL Shocks

LDA	Historical CETL Values				Simulation CETL Values		
	Average (MW)	Standard Deviation (MW)	Standard Deviation (%)	Count	2016/17 Value (MW)	Standard Deviation (MW)	Standard Deviation (%)
EMAAC	8,286	1,091	13%	10	8,916	1,090	12%
SWMAAC	7,140	1,095	15%	10	8,786	1,074	12%
ATSI	7,256	1,619	22%	3	7,881	963	12%
PEPCO	5,733	964	17%	5	6,846	837	12%
PSEG	6,241	387	6%	6	6,581	804	12%
MAAC	6,155	886	14%	7	6,495	794	12%
ATSI-C	5,093	216	4%	2	5,245	641	12%
PS-North	2,733	191	10%	8	2,936	359	12%
DPL-South	1,836	228	8%	6	1,901	232	12%

Sources and Notes:

Historical CETL values from Planning Parameters, PJM (2009a, 2009b, 2010, 2011, 2012, 2013a).

Simulation CETL values are equal to 12.2% of the 2106/17 CETL value.

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