UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. EL19-58-000**
	)	
PJM Interconnection, L.L.C.	**)**	**Docket No. ER19-1486-000**

ANSWER OF PJM INTERCONNECTION, L.L.C.

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I. INTRODUCTION AND EXECUTIVE SUMMARY

PJM Interconnection, L.L.C. ("PJM") hereby answers certain of the protests to and comments on PJM's March 29, 2019 filing[1] in these related Federal Power Act ("FPA") section 205[2] and 206[3] proceedings.[4] In the March 29 Filing, PJM detailed through extensive affidavits and historic data, how PJM's existing reserve pricing rules do not appropriately reflect in market clearing prices operator actions needed to ensure system reliability, as required by the Federal Energy Regulatory Commission's ("Commission") policy on price formation. As the Commission explained in Order No. 825, the objectives of "[b]etter formed prices [that] help ensure just and reasonable rates" include "provid[ing] transparency of the underlying value of the service so that

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[1] Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., Docket Nos. EL19-58-000, et al. (Mar. 29, 2019) ("March 29 Filing").

[2] 16 U.S.C. § 824d.

[3] 16 U.S.C. § 824e.

[4] Although Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. 213(a)(2), does not generally permit answers to answers, the Commission permits answers for good cause shown, such as when an answer ensures a more accurate and complete record or provides useful information that assists the Commission's deliberative process. *See, e.g.*, *N.Y. State Pub. Serv. Comm'n*, 158 FERC ¶ 61,137, at P 29 (2017) ("We will accept the Company's and the Complainant's answers because they have provided information that assisted us in our decision-making process."); *Colonial Pipeline Co.*, 157 FERC ¶ 61,173, at P 23 (2016) ("In the instant case, the Commission will accept the Protestors' Answers and Colonial's Answer because they have provided information that assisted us in our decision-making process."). This Answer will aid the Commission's decision-making process by responding to protestors' challenges to PJM's March 29 Filing and demonstrating that while PJM's current reserve market rules are unjust and unreasonable, its proposed replacement rules are just and reasonable. PJM therefore requests that the Commission accept this Answer.

operational and investment decisions are based on prices that reflect the actual marginal cost of serving load and the operational constraints of reliable system operation[;]" "providing appropriate incentives for market participants to follow commitment and dispatch instructions[;]" and "encourag[ing] efficient investments in facilities and equipment."[5] As particularly relevant here, "[a] failure to properly reflect in market prices the value of reliability to consumers and operator actions taken to ensure reliability can lead to inefficient prices in the energy and ancillary services markets leading to inefficient system utilization, and muted investment signals."[6] As the Commission's expert staff elaborated in that 2014 report, system operators like PJM need to "appl[y] administrative pricing rules to ensure that costs, including the costs associated with the failure to meet minimum operating reserve requirements, are reflected in market prices."[7]

Although the protests challenge many aspects of PJM's proposed remedy, none have successfully countered PJM's showing that its current reserve pricing rules do not satisfy these well-established price formation policies and objectives. As shown in the March 29 Filing, PJM's current reserve market rules do not adequately reflect either "the value of reliability to consumers" or the "operator actions taken to ensure reliability."[8] PJM does not neglect parties' attempts to undermine PJM's showing that its current rules are unjust and unreasonable (and forcefully rebuts those arguments in this answer), but urges the Commission to maintain separation (as required by FPA section 206) between,

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[5] *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276, at P 163 (2016).

[6] Bob Hellrich-Dawson, *Staff Analysis of Shortage Pricing in RTO and ISO Markets* Federal Energy Regulatory Commission, 1 (Oct. 21, 2014), https://www.ferc.gov/legal/staff-reports/2014/AD14-14-pricing-rto-iso-markets.pdf.

[7] *Id.*

[8] *Id.*

on the one hand, identification of the major shortcomings in the current rules and, on the other hand, attacks on the algorithms, assumptions, and alleged effects of PJM's particular proposed solution (which PJM also rebuts herein). As the Commission focuses on that distinct FPA section 206 question regarding the reasonableness of PJM's current rules, it is telling that protestors have barely acknowledged, let alone attempted to reconcile, the Commission's explicit guidance on price formation policies with the present pricing of reserves in PJM.

As summarized below, PJM structures this answer to follow the bifurcated approach dictated by FPA section 206 (i.e., first, addressing the facts and argument that affirm PJM's current reserve market rules are unjust and unreasonable, and second, defending PJM's proposed replacement market rules as just and reasonable). This answer also rebuts speculative efforts to contend that PJM's capacity market rules could (following implementation of PJM's proposed reserve market rules) become unjust and unreasonable, as unpersuasive and outside the scope of this proceeding.

PJM's Current Reserve Market Rules are Unjust and Unreasonable

PJM has provided substantial evidence in this proceeding to show that PJM's current reserve market rules are unjust and unreasonable:

> (1) A large share of Synchronized Reserve sellers are simply deemed by the Open Access Transmission Tariff ("Tariff") to be providing that service, but they face no consequences for failure to perform, and not surprisingly exhibit poor performance;
>
> (2) PJM system operators are regularly biasing their dispatch schedules to manage significant load and resource forecast uncertainties, but their actions—effectively substituting for reserves—are not reflected in the market price for reserves;
>
> (3) PJM's current Operating Reserve Demand Curve ("ORDC") does not adequately account for the load and resource forecast uncertainties that operators are addressing through out-of-market action;

> (4) PJM reserve market prices are not signaling a need for reserves even during especially tight conditions like those seen in January 2019; and
>
> (5) the current maximum price on the ORDC is not high enough to reflect the legitimate opportunity costs of sellers that can provide energy rather than reserves.

Protestors' attempts to minimize the substantial shortcomings in the current rules are unconvincing. Contrary to protestors, current reserve market pricing is not properly reflecting competitive supply and demand because (a) supply is skewed by the merely deemed, and substantially non-performing, Tier 1 reserves; and (b) demand for reserves is poorly reflected in the current administratively designed ORDC because, simply, it is not currently designed to incorporate the various load and resource uncertainties that drive the need for reserves.

Protestors also oversell the ORDC's current Step 2A and Step 2B as means to address operational uncertainties. Step 2A is already an automatic, self-implementing feature of the current curve, and PJM operators regularly resort to dispatch biasing even with that self-implementing step in place. Step 2B has not yet been invoked, and is not suited to procuring reserves to mitigate the net uncertainty from the continual interactions of inevitable load and resource forecast errors.

Parties arguing that the solution is to adopt improved forecast methods or operator training are ultimately proposing—contrary to Commission policy—that consequential operator actions should not be reflected in market prices. PJM already implements extensive improved forecasting and training practices (including the type of actions outlined in the affidavit of PJM Load/Customer Coalition ("Load Coalition") witness Mr.

Rao Konidena[9]—the relevant question is whether the prices produced in the market should continue to ignore the significant operator actions that still, of necessity, occur on a regular basis.

<u>PJM's Proposed Replacement Rules for the Reserve Market Are Just and Reasonable</u>

PJM has proposed rules that directly address and resolve the deficiencies demonstrated in the current rules, including: (1) consolidation of Tier 1 and Tier 2 Synchronized Reserves into a single product with clear commitments and consequences for non-performance; (2) an updated Reserve Penalty Factor to account for seller opportunity costs from not selling energy or load reductions; (3) a revised ORDC shape beyond the MRR to incorporate systematic determination of the probabilities of falling below the minimum reserve requirement ("MRR"); and (4) alignment of the day-ahead and real-time reserve products to include both a primary and secondary reserve product in both markets.[10]

Protestors' efforts to undermine PJM's showings are unsuccessful. Their claim that PJM's proposed rules will reward inflexible resources has it exactly backward. Improved reserve market pricing incents and rewards resources that can best provide the operating flexibility that is the defining characteristic of 10-minute (i.e., primary) and 30-minute (i.e., secondary) reserves. These more flexible units will be chosen to provide reserves over their more inflexible and inefficient resources and provide the kind of flexible services PJM will increasingly need as the profile of the fleet changes markedly. Of course, for those units that remain, if improved reserve pricing also increases the

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[9] Affidavit of Rao Konidena on Behalf of the PJM Load/Customer Coalition ("Konidena Aff.") (Attachment E to Load Coalition Protest). The Konidena Aff. is included as Attachment E to the Protest of the Load Coalition. *See* n.19, *infra*.

[10] As the protests present little if any facts or arguments to rebut the March 29 Filing's showings on the day-ahead/real-time alignment issue, PJM has chosen not to address that issue in this answer.

energy revenues paid to multiple resource types, that is a consequence of efficient pricing and co-optimization—market features Commission policy has long encouraged. Protestors' complaints in this area effectively ask the Commission to turn the bid stack on its head—an argument unsound in merit and, in any event, far beyond the scope of this case which focuses on appropriate pricing of reserves in the PJM market.

Claims that the proposed ORDCs will over-procure reserves also fail. Reserves above the MRR have value, and that value is reasonably defined in terms of the probabilities of falling below the MRR as PJM has amply demonstrated on the record in this proceeding.[11] So the real question is whether, as part of an FPA section 206 remedy, PJM's method reasonably estimates those probabilities. This answer fully rebuts the critiques of that methodology.

Protestors Have Not Demonstrated that the Existing Capacity Market's Rules for Estimating Energy and Ancillary Services ("EAS") Revenues Will Be Rendered Unjust and Unreasonable by the Proposed Reserve Market Reforms, or that Substantial Capacity Market Changes Are Appropriately Addressed in this Proceeding.

PJM already has a Commission-approved mechanism to reflect changes in energy and ancillary services revenues in the Net Cost of New Entry ("CONE") parameter used to set the Variable Resource Requirement ("VRR") Curve in PJM's capacity auctions, and PJM has not proposed any changes to that existing mechanism in this proceeding. Protestors have not provided substantial evidence that the reserve market changes proposed in this case will render the existing EAS rules unjust and unreasonable. Nor could they, given the many factors aside from the reserve market (including fuel costs

[11] *See generally*, Reply Affidavit of Drs. William W. Hogan and Susan L. Pope on Behalf of PJM Interconnection, L.L.C., Exhibit 1 (PJM Reserve Markets: Operating Reserve Demand Curve Enhancements – Reply Comments) ("Hogan & Pope Reply") (Attachment A herein); Reply Affidavit of Dr. Patricio Rocha Garrido on Behalf of PJM Interconnection, L.L.C. ("Rocha Garrido Reply Aff.") (Attachment D herein).

and resource portfolio changes) that will profoundly affect future energy prices and revenues. But even if protestors had shown significant impacts on the EAS to be a possibility, that would not compel whole scale Commission changes in this case to the capacity market rules. The Commission has ample discretion to structure its proceedings,[12] and has often considered in subsequent proceedings whether an earlier tariff change warrants changes (even under FPA section 206) to other tariff provisions. Rather than introduce sudden changes or volatility into an EAS that has worked reasonably well (and that has been repeatedly reaffirmed despite periodic calls for change), the better course would be to wait to see whether the actual effects of reserve market changes warrant any changes to the EAS rules.[13]

II. SUBSTANTIAL RECORD EVIDENCE SHOWS THAT PJM'S CURRENT RESERVE MARKET RULES ARE UNJUST AND UNREASONABLE.

A. Contrary To Protestors, The Record Evidence Demonstrates That PJM's Current ORDC Shape Is Unjust And Unreasonable Because It Does Not Adequately Reflect The Reliability Value Of Procuring Reserves Above The Minimum Reserve Requirement.

As the Commission assesses the protests in this case, it should not lose sight of the essential question at issue here concerning the shape of PJM's current ORDC:

Does the ORDC as currently designed reasonably reflect the reliability value of reserves procured above the MRR?

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[12] Hogan & Pope Reply at 5; *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs*., 139 FERC ¶ 61, 212, at P 16 (2012) (citing *Mobil Oil Expl. & Producing S.E. Inc. v. United Distrib. Cos.*, 498 U.S. 211, 230-31 (1991)).

[13] As discussed below in Section V of this answer, if the Commission does find it necessary a need to address some manner of EAS transition in this proceeding, it should ensure that: (i) any such changes do not seek to reopen Base-Residual Auctions ("BRAs") that have already run, or seek to take back revenues already allocated pursuant to those BRAs; and (ii) any transition mechanism for subsequent Delivery Years where a BRA has not yet been conducted should be limited in scope and narrowly address the concern about how long it will take for the capacity market to catch up with the changes in expected energy and ancillary service revenues.

In other words, the operative issue is not *whether* to assign positive value to reserves above the MRR—PJM's current ORDC already does so. Rather, the issue is *how* to reasonably value reserves above the MRR, and does PJM's current ORDC design provide such reasonable valuation for the PJM Region?

Abundant evidence in this record (summarized here and reiterated in the following subsections) shows the current ORDC does not meet the Commission's price formation objective to, as applied here, reasonably reflect in market prices the reliability value of procuring reserves above the MRR:

- The current ORDC design assumes that reserves needed to address most of the sources of the probability of falling below the MRR have zero value; for example, the ORDC assigns a positive price to only 190 megawatts ("MW") of reserves above the MRR ("Step 2A"), but observed wind forecast error alone in PJM has averaged 160 MW;[14] thus the ORDC largely ignores (and fails to price) the effects of other uncertainties (i.e., solar output, load, thermal outages, interchange) that could cause the PJM Region to fall below the MRR.
- The current ORDC design also includes a contingent step for procuring reserves above the MRR ("Step 2B") that is triggered only when PJM enters "Conservative Operations" that entail atypical restrictions on market participants' use of the bulk power system, which thus fails to price reserves needed on an ongoing basis to meet documented uncertainties.[15]
- PJM operators are regularly taking out-of-market action to bias dispatch schedules [in part] to mitigate load and resource forecast uncertainties, but those actions are not reflected in market prices. The Operators' actions are certainly appropriate to address reliability and ensure sound real time operation, but failure to reflect these actions in market prices is especially problematic when PJM would have triggered pricing at the reserve penalty factor had the biasing not occurred.[16]
- The inherent uncertainties in wind resource forecasts, solar resource forecasts, load forecasts, and expected thermal plant outage levels that prompt out-of-market operator actions are the very factors that most influence whether reserves will fall short of the MRR, but the current ORDC is simply not designed to address all those uncertainties, the probability that they will cause

[14] *See infra* at 14-16.

[15] *See infra* at 16-18.

[16] *See* March 29 Filing at 6-7.

reserves to fall below the MRR, or the value in preventing reserves from falling below the MRR.[17]

- Unlike when the ORDC was first established in 2012, uncertainties associated with the output of intermittent resources will grow as renewable resources are expected to substantially grow their share of the resource portfolio.
- PJM Region Synchronized Reserve prices were demonstrably suppressed during severe cold weather conditions this past winter, clearly showing the shortcomings in PJM's current reserve market rules.[18]

In response, protestors broadly argue that PJM cannot make an FPA section 206 showing unless PJM shows that reserve prices have caused an extended reserve shortage.[19] Some assert that PJM should continue to rely solely on the limited steps beyond the MRR in the current ORDC,[20] while the Independent Market Monitor ("IMM") maintains (contrary even to the existing ORDC) that the curve must always drop to zero price immediately after the MRR, although the IMM would also allow for conditional rightward shifts in the vertical curve at the MRR.[21] Protestors also suggest that a more refined and systematic downward sloping ORDC is impermissible for a Regional Transmission Organization ("RTO") with a capacity market.[22] Last, protestors question the significance of PJM operator actions to bias dispatch, and of the very low Synchronized Reserve prices observed early this year under stressed conditions.[23]

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[17] *See id.* at 7; Affidavit of Dr. Patricio Rocha Garrido on Behalf of PJM Interconnection, L.L.C. ¶¶ 11-12 ("Rocha Garrido Initial Aff.") (Attachment F to March 29 Filing).

[18] *See infra* at 29-30; March 29 Filing at 20-22.

[19] *See* Maryland Public Service Commission Protest and Comments, Docket Nos. EL19-58-000, et al., at 2, 8 (May 15, 2019) ("MdPSC Protest"); Protest of the PJM Load/Customer Coalition, Docket Nos. EL19-58-000, et al., at 3-4 (May 15, 2019) ("Load Coalition Protest"); Comments and Limited Protest Submitted on Behalf of the Staff of the Public Utilities Commission of Ohio, Docket Nos. EL19-58-000, et al., at 11 (May 15, 2019).

[20] *See* MdPSC Protest at 6-11; Load Coalition Protest at 30-32.

[21] Protest of the Independent Market Monitor for PJM, Docket Nos. EL19-58-000, et al., at 13-15, 65-66 (May 15, 2019) ("IMM Protest").

[22] IMM Protest at 18-19.

[23] MdPSC Protest at 5-6; IMM Protest at 61; Load Coalition Protest at 73-76; Konidena Aff. ¶ 12.

As a threshold matter, the Commission has long held that an RTO need not wait for a reliability emergency before seeking reforms under FPA section 206.[24] Any such holding would straitjacket the Commission and RTOs from taking prudent proactive steps to address market rule changes that can improve both operations and prices and would create a very poor precedent for the Commission going forward.

Beyond this overview, PJM addresses the specifics of each of these arguments in the following subsections of this answer.

1. Parties that contend current reserve market prices appropriately reflect supply and demand ignore the fundamental shortcomings in the current reserve market's constructs for both supply and demand.

The IMM accuses PJM of seeking to place a higher value on reserves "regardless of supply and demand conditions;" and of sacrificing "efficient market prices" and "economic fundamentals" in pursuit of PJM's "operational need for reserves."[25] In the IMM's view, zero prices for Synch Reserves in about 60 percent of all hours, and in 98 percent of all hours for Non-Synch Reserves, reflects such economic fundamentals.[26] The IMM's argument ignores, however, the severe flaws PJM documented in the March 29 Filing for both supply and demand in the reserve market. PJM agrees that basic supply and demand fundamentals are critical. But today's rules skew both the supply and demand for reserves, as shown below. Thus, the issue is not whether "supply and demand" are important—of course they are. The question is whether the ample evidence

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[24] *See, e.g.*, *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at P 4 (2015) (implementing reforms to the PJM Capacity market because "PJM has demonstrated the need for these reforms to ensure the long-term reliability of electric supply in the PJM region"), *order on reh'g*, 155 FERC ¶ 61,157 (2016).

[25] IMM Protest at 13.

[26] *Id.*; *see also* Load Coalition Protest at 18-22.

PJM submitted demonstrates that the present market rules impede the effects of such "economic fundamentals."

Specifically, supply is skewed today by market rules that deem Tier 1 sellers to be providing reserves at zero price even though they have not offered, or been committed, to provide reserves. As shown in the March 29 Filing, only about 60 percent of the reserves estimated from Tier 1 actually responds, highlighting the current supply-side flaws. The IMM responds by pointing out that other resources, on which PJM *has not* estimated Tier 1, may respond as well.[27] But that phenomenon only underscores the difficulty in constructing an accurate supply curve when a significant portion of the purported reserve suppliers have no obligation to respond. Hoping others suppliers respond, when a significant contingent of suppliers with no obligation to respond in fact *don't* respond, is not a reasonable administrative market construct—but this is the construct PJM has today. As Mr. Keech concludes in his Reply Affidavit, use of the Tier 1 product as part of the Synchronized and Primary Reserve supply curves makes it virtually impossible to calculate accurate prices. Plainly, and contrary to the IMM, today's reserve market rules are not a formula for "efficient market prices."[28]

Similarly, reserve market demand today is not (contrary to the IMM) determined by "economic fundamentals,"[29] but by a constrained and an overly simplistic demand curve, i.e., the current ORDC. That current demand curve does not reflect the need for reserves that load and resource forecast uncertainty creates for system operators. The result is a demand for reserves that is too low, prompting operator dispatch schedule

[27] IMM Protest at 19-20.

[28] IMM Protest at 13.

[29] *Id.*

biasing and other out-of-market actions to mitigate the substantial uncertainty the current demand curve ignores. In other words, the demand dictated by the Tariff-prescribed ORDC today artificially constrains the level of reserves eligible for compensation at a level that does not reflect demonstrated needs for procurement of additional reserves by PJM operators. That disconnect between the current ORDC and the system's need for reserves will only grow as the portfolio share of intermittent resources steadily climbs in the coming years.

The observed market results are symptomatic of the existing rules' skewed supply and demand. As Mr. Keech explains in his Reply Affidavit, 2018 market results show a zero price in 56.8 percent of hours for the Synchronized Reserve Market Clearing Price and in 97.5 percent of the hours for the Non-Synchronized Reserve Market Clearing Price.[30] That incidence of hours with zero pricing drops precipitously, to only 8.8 percent and 9.7 percent, respectively, when PJM runs a market simulation that corrects the current supply and demand deficiencies, i.e., the supply curve does not rely on Tier 1 and the demand curve systematically incorporates the same uncertainties faced by operators.[31] This demonstrates that the current prevalence of zero prices is *not* an efficient outcome of market supply and market demand (as the IMM suggests), but rather a consequence of shortcomings in the current rules that strongly affect supply and demand. Mr. Keech also rightly points to another clear symptom of these market design flaws: roughly *fifty*

[30] Reply Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C. ¶ 32 ("Keech Reply Aff.") (Attachment B herein).

[31] *Id.*

percent of the current reserve market is settled through *uplift* payments—a statistic that, if observed in a larger market, would command prompt corrective measures.[32]

As Mr. Keech summarizes, the extreme prevalence of zero prices in the PJM reserve market, far from signaling "economic fundamentals" working as they should, is consistent with PJM's documented current conditions of (1) a supply curve that is artificially flat due to deemed Tier 1 supply; (2) a demand curve that is artificially short due to failure to reflect material uncertainties that reserves should address; (3) a market where reserve prices are persistently quite low; and (4) a market in which a significant percentage settles through uplift.

In short, these anomalies, which are unique to the PJM Region, argue strongly for a finding under FPA section 206 that the current market rules are unjust and unreasonable, and for replacement terms to correct these errors in the current Tariff rules that skew both supply and demand in this market

To meet that need, PJM proposes improvements to both of these administrative influencers of supply and demand by (1) requiring sellers to step up and commit to provide reserves with both compensation and non-performance charge incentives; and (2) basing the ORDC on a more rigorous definition of the objective such a curve reasonably should address (i.e., the risk of falling below the MRR based on a probabilistic analysis of uncertainties). As discussed in a later section, PJM also proposes to relax a current constraint on supply by revising the penalty factor that prevents sellers from reflecting legitimate costs in their reserve offers.

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[32] *Id.* ¶ 33.

2. The current ORDC steps beyond the MRR are inadequate.

Several protestors argue that no changes are needed to the ORDC because the current ORDC already allows PJM to procure additional reserves beyond the MRR, and PJM should use that existing authority to address any operational concerns.[33]

Contrary to the impression created by these protestors, the existing ORDC steps are not a solution, or alternative, to the dispatch schedule biasing and other out-of-market operator actions PJM detailed in the March 29 Filing. As discussed below, Step 2A—defined by a fixed price and fixed quantity above the MRR—is already factored into PJM's real-time scheduling in the same way as the MRR and the Penalty Factor. Yet, as shown in the March 29 Filing,[34] operators still rely extensively on schedule biasing. As also discussed below, Step 2B has never been invoked simply because the operator needs have not arisen under the very specific emergency conditions under which it can be invoked; nor is that step well suited to addressing continuous load and resource output forecast uncertainties. The existing steps in the current ORDC beyond the MRR are therefore simply not sufficient to alleviate the uncertainties faced by PJM operators.

First, Step 2A is not discretionary. Although it *formerly* applied only in the conditions described by the Maryland Public Service Commission ("MdPSC"),[35] Step 2A was revised in 2017 to be permanent.[36] Consequently, Step 2A establishes automatic pricing, at $300/megawatt hour ("MWh"), of reserves procured in any amount up to 190 MW above the MRR. The dispatch tools used by PJM operators thus assume such

[33] *See, e.g.*, Load Coalition Protest at 30-32; MdPSC Protest at 6-7.

[34] March 29 Filing at 35-37.

[35] MdPSC Protest at 9-10.

[36] Submission of PJM Interconnection, L.L.C., Docket No. ER17-1590-000, at 7-8 (May 12, 2017) ("Step 2A Filing").

reserve purchases will occur at that price, in the same way they assume reserves will be purchased at the Penalty Factor up to the MRR. Because Step 2A is automatic, PJM operators do not choose to bias schedules *instead of* invoking Step 2A; rather they continue to bias even considering Step 2A.

Notably, when PJM justified making Step 2A permanent in 2017, it did so in terms that emphasized the downward-sloping character of that step (i.e., explaining that Step 2A employs a price lower than the penalty factor for reserve MWs beyond the MRR).[37] Step 2A is inadequate, however, because its maximum quantity—190 MWs—is only a fraction of the combined potential forecast errors operators must manage in their dispatch, as described in Dr. Rocha Garrido's Initial Affidavit in this proceeding.[38] Rather than address those uncertainties, the 190 MW step was designed to prevent transient reserve deficits that would cause quick price spikes. To that end, the 190 MW value was the average synchronized reserve deficit shown on Real-time Security Constrained Economic Dispatch ("RT SCED") over a fourteen-month period prior to the implementation of transient shortage pricing.[39] That 190 MW step therefore was simply not designed to address the problem confronted by this filing (i.e., more accurately price reserves based on the prevalence and magnitude of the underlying suite of uncertainties that give rise to the value of reserves). Thus, Step 2A in its current form was part of a more limited reform that did not address the uncertainties that have and will continue to drive operator actions that are not reflected in price.

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[37] *See* March 29 Filing at 25-26.

[38] Rocha Garrido Initial Aff. ¶¶ 11.

[39] *See* Step 2A Filing at 7-8; *see also* Adam Keech, *Shortage Pricing ORDC - Order 825*, PJM Interconnection, L.L.C., 7 (Oct. 26, 2016), https://www.pjm.com/~/media/committees-groups/committees/mic/20161026-special/20161026-item-03-shortage-ordc.ashx.

Similarly, PJM is not (contrary to protestors' suggestion) ignoring Step 2B as a tool to reduce operational uncertainty. Rather, Step 2B was intended to address a variety of out-of-the-ordinary, or emergency events or conditions. Reflecting this intent, Step 2B as currently implemented through the PJM Manuals allows PJM to procure more than 190 MW of reserves at $300/MWh, but only when PJM declares "Conservative Operations." Conservative Operations cover such events as fires threatening major transmission lines, hurricanes, tornados, geo-magnetic disturbances, and credible threats of physical or cyber-attacks.[40] The hallmark of Conservative Operations is operating the system with "conservative transfer limit values, selected double-contingencies, and/or maximum credible disturbances."[41] Reflecting that narrow focus, Step 2B has not yet been invoked,[42] because the conditions it is intended to address have not occurred since Step 2B was made effective.

Operator dispatch biasing, on the other hand, is meant to create headroom in the face of general uncertainty that is constantly present (e.g., how well units will follow dispatch, reserve estimations, forecast uncertainty, etc.). Because this uncertainty is always present and it is harder to accurately predict the amount of such uncertainty (unlike estimating a specific quantity of reserves needed to make up (for example) for the heightened threat of a particular unit tripping), the Step 2B approach is not practical as a long-term solution that would be used constantly in real-time.

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[40] *See* PJM, *Manual 13: Emergency Operations*, section 3.2 (rev. 70, May 30, 2019), https://www.pjm.com/~/media/documents/manuals/m13.ashx.

[41] *Id.* at section 3.2.

[42] In response to the Load Coalition Protest (at 30-31), PJM acknowledges that, while it submitted the report on ORDC step implementation for the 2015/2016 Delivery Year, PJM overlooked submission of the report for the 2016/2017 Delivery Year. This was merely an oversight which PJM addressing, and should not affect the Commission's consideration of the present filing. PJM notes that the experience in 2016/2017 generally tracks that reported for 2015/2016.

Thus, contrary to protestors, Step 2B is not the answer to the operational concerns detailed in the March 29 Filing.

3. Contrary to the IMM, reserves beyond the MRR have value.

The IMM takes the position that reserves beyond the MRR should have a zero price, i.e., that the ORDC should be vertical and drop to zero at the MRR (although, as discussed in the next section, the IMM also suggests *moving* the MRR episodically).[43] The IMM argues that assigning positive value to reserves above the MRR signals scarcity pricing when there is no shortage, and will inefficiently induce load to leave the PJM system.[44] The IMM's philosophy on the ORDC is at odds with their longstanding support (reiterated in the most recent quadrennial review)[45] of a downward-sloping demand curve in the PJM capacity market. As PJM showed in the March 29 Filing, the Commission has frequently found value to procurement of capacity above the Installed Reserve Margin,[46] which is directly comparable to valuing reserves procured beyond the MRR.

The Commission should reject the IMM's dogmatic view that reserves above the MRR must be priced at zero. As Drs. Hogan and Pope explain, "there is a principled basis for PJM's construction of an operating reserve demand curve [that] is comprised of the fixed price over the range from zero to the MRR, and a declining price over

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[43] IMM Protest at 13-15, 65-66.

[44] *Id.* at 23-26.

[45] *See* Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters of PJM Interconnection, L.L.C., Docket No. ER19-105-000 (Oct. 12, 2018); *see also* Protest of the Independent Market Monitor, Docket No. ER19-105-000, at 19-20 (Nov. 19, 2018).

[46] *See* March 29 Filing at 38-39, nn.74-78 (citing *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006), *order on reh'g*, 119 FERC ¶ 31,318, at P 99 (2007)).

increasing levels of reserves above the minimum level."[47] As they explain, "reliability requirements constrain the feasible real-time economic dispatch;" including "minimum levels of operating reserves that must be set just before the start of each dispatch interval."[48] In addition to that need to satisfy the reliability constraint (i.e., the MRR, before the start of each dispatch period), there is "uncertainty about the availability of sufficient reserves over future dispatch intervals."[49] For example, "[i]f there is a call on the operating reserves [in the future], and the reserve level then falls below the MRR constraint, the system operator will have to invoke emergency actions and the system will see the costs of the penalty factor."[50] Consequently, "the probability of this event, multiplied by the penalty factor, defines the implied value of scheduling a marginal unit of operating reserves above the MRR."[51]

In short, procuring reserves beyond the MRR to reasonably *avoid* the costs of emergency actions that will be taken when reserves fall below the MRR (such as avoiding the cost of paying the penalty factor) has value. Reserves procured to keep reserve levels above the MRR have value in reducing that risk of falling below the MRR. In short, a sound market design recognizes the value (albeit at declining values as reserves increase) in order to avoid emergency actions rather than forcing the system to go into emergencies before additional reserves are procured and compensated.[52]

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[47] Hogan & Pope Reply at 6.

[48] *Id.* at 5.

[49] *Id.*

[50] *Id.* at 5-6.

[51] *Id.* at 6.

[52] As an analogy, cars have spare tires because of the value of having that resource available in an emergency notwithstanding that the spare tire may negatively impact a car's fuel efficiency due to its weight. Few drivers would conclude that the spare tire in their trunk provides them no value even if it is never actually used.

The IMM's view that an ORDC should not pay any price for reserves above the MRR also runs headlong into the Commission's prior acceptance of PJM's current ORDC, which already pays a positive price for reserves procured above the MRR. Thus, regardless of whether the IMM labels a non-zero price for reserves above the MRR as scarcity pricing, the Commission has already accepted that form of pricing as just and reasonable.

4. *The IMM's proposal for a shifting vertical curve only highlights the flaws in his claim that reserves beyond the MRR have no value.*

The IMM attempts to redeem its insistence on a vertical curve at the MRR by allowing for "update[s] [to] the reserve requirement when [PJM] needs additional flexibility."[53] But this proposal for an ad hoc shifting of the MRR has two clear flaws, as shown by Dr. Rocha Garrido.

First, it begs the question of *the magnitude* of the shift. When PJM wants to redefine the MRR so as to procure more reserves, how is the additional procurement quantity determined? The IMM proposes to assign responsibility to PJM system operators for determining the magnitude of this recurring market design change (i.e., each instance of a rightward shift in the vertical ORDC would be "a result of operator actions to procure additional reserves based on operator uncertainty, inaccurate forecasts, or conservative operations").[54] However, as Dr. Rocha Garrido explains, while "PJM operators ably perform their essential reliability role . . . tying reserve prices so directly to individual operators' assessments of uncertainty is clearly not the best market design."[55]

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[53] IMM Protest at 15.

[54] IMM Protest at 15.

[55] Reply Affidavit of Dr. Patricio Rocha Garrido on Behalf of PJM Interconnection, L.L.C. ¶ 10 ("Rocha Garrido Reply Aff.") (Attachment D herein).

If the IMM instead intends that PJM use a pre-determined systematic method to quantify the additional reserves needed, then that simply reinforces the need for an ORDC method like that proposed here by PJM, which uses a systematic estimate of possible reserve shortfalls.

Second, the IMM's right-shifted MRR apparently maintains the same penalty factor as the original MRR. This ignores that the operational choice to obtain additional reserves implicitly involves a probability of whether those reserves will actually be needed to prevent a reserve shortfall. That probability—which is less than 100 percent—indicates that the price for that extra increment of reserves should be something less than the full penalty factor.[56] Recognizing and reasonably determining that lower price is exactly what PJM proposes with its ORDC methodology.

Therefore, the IMM's proposal for a floating MRR ultimately serves only to highlight the merits of a systematic, probabilistic approach like that proposed here by PJM.

5. A downward-sloping ORDC is not incompatible with a capacity market.

Several protestors argue that a downward-sloping ORDC is not needed in PJM, because the PJM Region has a capacity market, and the market with a somewhat similar ORDC (i.e., the Electric Reliability Council of Texas ("ERCOT")), does not have a capacity market. Drs. Hogan and Pope, who helped ERCOT design that ORDC, strongly disagree with that argument, pointing out that "efficient design of the operating reserve demand curve. . . is not affected by the capacity market."[57]

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[56] *See* Rocha Garrido Reply Aff. ¶ 11-12.

[57] *See id.*

As they explain, "long-term [] adequacy rules focus on [] planning requirements and installed capacity" which "look many years ahead" and use planning models "that are quite distinct from. . . the real-time operation of the system."[58] In other words, the focus is on the accepted one-day-in-ten-years type reliability standard. Similarly, the studies that "provide the foundations for the demand and supply representations in forward capacity auctions" focus on "aggregate capacity [and] peak system load."[59] By contrast, "the purpose of operating reserves is to address the short-term uncertainties and maintain secure operations within the [reliability window],"[60] including "[p]lant outages, unscheduled maintenance, intermittent supply, surprising load conditions and a host of other related situations create reliability challenges."[61] These operational needs exist regardless of whether there is a capacity market. The IMM's argument boils down to one that suggests that because PJM has a capacity market, there is no real-time operational uncertainty. Taken a step further, this argument suggests that PJM's real-time load, solar, and wind forecasts are 100 percent accurate, that all generation in PJM performs as expected at all times, and that all of those (unrealistic) conditions exist because PJM has a capacity market. Clearly these conclusions are not reasonable and thus the IMM's argument is unsupportable.

Given this, and the fundamental differences between reserve markets and resource adequacy markets, "the efficiency principles that drive the design of the operating reserve demand curve should not be modified in the presence or absence of a capacity market."[62]

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[58] *Id.* ¶ 10.

[59] *Id.*

[60] *Id.* at 4.

[61] *Id.*

[62] *Id.* at 4.

6. *PJM's experience plainly shows operator actions that currently are not, but should be, reflected in reserve prices; and those PJM operator actions already take account of operating practices and tools like those suggested by the Load Coalition.*

In the March 29 Filing, PJM showed that PJM dispatchers regularly bias their scheduling of supply resources to manage the uncertainty inherent in near-term forecasts of load, wind generation, and solar generation (or for unexpected plant outages), and that dispatchers are also taking other out-of-market actions to preserve reliability. Although these operator actions relate directly to the possibility that the PJM system could fall short of the MRR, these actions are not accounted for in reserve or energy market clearing prices.[63] As PJM explained, failure to reflect these actions in market prices is especially a concern when such actions prevent the market from seeing what would otherwise be reserve shortages—which, as PJM showed in the March 29 Filing, has happened to a significant degree on the PJM system.[64]

In response, the Load Coalition argues that the Commission should direct PJM to explore how to address these significant operator actions in ways *other* than reflecting them in market prices, such as "consider[ing] updates and changes to [PJM's] models, training, tools, and procedures."[65] In that regard, the Load Coalition presents the affidavit of Mr. Konidena, a former MISO employee, to describe the operator training and other methods MISO used to limit the need for operator interventions.[66]

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[63] March 29 Filing at 6; Pilong Initial Aff. ¶¶ 18-20.

[64] March 29 Filing at 6, 30; Pilong Initial Aff. Table 1 (demonstrating possibility that in 29.1 percent of all five-minute intervals in 2018, PJM operations would have been short reserves absent positive bias applied in scheduling engines for that interval).

[65] Load Coalition Protest at 76.

[66] *See* Konidena Aff. ¶¶ 11-19.

While PJM agrees with the Load Coalition on the importance of quality forecasting tools and training to reduce the need for operator interventions, the Load Coalitions' ultimate request is simply to urge the Commission not to reflect PJM's operator actions in the market.[67] That plea runs directly counter, however, to the Commission's policy for price formation that "provide[s] transparency of the underlying value of the service so that operational and investment decisions are based on prices that reflect the actual marginal cost of serving load and the operational constraints of reliable system operation."[68]

Moreover, PJM *already* follows the types of operational practices noted by Mr. Konidena. As stated by Mr. Pilong in his Reply Affidavit, "PJM agrees" with the need for the reviews, analysis, and training MISO uses "to ensure that they are maintaining accurate forecasts and minimizing operator intervention."[69] As Mr. Pilong details, "PJM also performs similar reviews and analysis with the same goals in mind."[70] *Notwithstanding* those rigorous practices, PJM operators still find it necessary to take actions to assure reliability that can significantly affect the quantity of reserves PJM otherwise would procure, and the price the PJM Region pays for those reserves. In accordance with Commission policy, market rules should be modified to better reflect those actions.

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[67] Load Coalition Protest at 76.

[68] Order No. 825 at P 163.

[69] Reply Affidavit of Christopher Pilong on Behalf of PJM Interconnection, L.L.C. ¶ 10 ("Pilong Reply Aff.") (Attachment C herein).

[70] *Id.*

7. The IMM's attempt to expand this FPA section 206 proceeding to address the PJM Energy Market is wide of the mark and will make it impossible for the Commission to address, in an orderly way, discrete identified problems with the PJM Reserve Market.

The IMM alleges that PJM's proposal to rectify the unjust and unreasonable reserve market design also requires the Commission to find PJM's energy market design to be unjust and unreasonable, arguing that PJM's proposal "changes the calculation of energy prices."[71] This is incorrect. Since 2012, PJM's real-time energy, Synchronized Reserve, and Non-Synchronized Reserve markets have been cleared using a joint co-optimization algorithm to achieve the least-cost solution.[72] Co-optimization ensures just and reasonable pricing of the separate services being co-optimized by selecting the solutions for each market with the lowest overall production cost.[73] Further, co-optimization of energy and reserves allows the energy price to reflect both the marginal energy offer plus the marginal cost of reserves. The Commission approved this approach,[74] and found that "joint optimization will allow for competition between reserve-to-energy conversions and emergency energy resources, including emergency purchases, during periods of shortage."[75]

[71] IMM Protest at 8.

[72] *See, e.g.*, Operating Agreement, Schedule 1, section 2.5(a) (providing that PJM "shall determine the least costly means of obtaining energy to serve the next increment of load" by "applying a real-time joint optimization of energy and reserves, given actual system conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any binding transmission constraints that may exist.").

[73] *See* Hogan & Pope Reply at 7 ("The scarcity price of reserves will interact with energy dispatch through co-optimization to determine consistent energy and reserve prices that support the efficient outcome.").

[74] *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057, at P 79 (2012); *see also ISO New England Inc.*, 130 FERC ¶ 61,054, at P 88 (2010) (finding that "the use of [the operating reserve] demand curve is an effective way to reflect the economic value of reserve shortages in energy and reserve prices in a co-optimized energy and ancillary services market").

[75] *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057, at P 79.

The fact that co-optimization of energy and reserves allows the energy price to reflect both the marginal energy offer plus the marginal cost of reserves has two important consequences that are relevant here. First, to ensure co-optimization works as intended, reserve market pricing rules must be just and reasonable. Second, ensuring correct pricing of reserves will result in more efficient pricing of energy that is co-optimized with reserves. Both of these factors point to the same relevant conclusion for purposes of this case: flaws in the reserve market pricing rules should be corrected, and doing so will be beneficial not only for efficient reserve pricing, but will have an ancillary benefit of efficient energy pricing. Co-optimization does not, however, mean (as protestors seem to suggest) that PJM cannot address flaws in the reserve market unless it also demonstrates flaws in the energy market.

The March 29 Filing does not change this fundamental approach. The difference will be that the marginal cost of reserves may exceed zero when PJM procures reserves above the minimum reserve requirement. As explained in the March 29 Filing, PJM proposed tariff revisions to "more explicitly spell[] out PJMs current approach, and expand[the rules] to include the ORDCs in the Locational Marginal Pricing ("LMP") calculation outside of shortage events as the ORDCs interact with the calculation of LMP in the same manner regardless of whether or not the minimum reserve requirements can be met."[76] In other words, PJM's proposed ORDC will have a different value for reserves beyond the MRR than what is used today. This will likely produce LMPs that are different from those that would be calculated using the current ORDC.[77] *This does not mean the LMP calculation will change.* The LMP calculation will remain the same as

[76] March 29 Filing at 104.

[77] *See, e.g.,* Keech Initial Aff. at ¶ 33-46 (describing PJM market simulation results)

it is today. What is changing is how reserves are valued in the joint optimization process by using a more accurate ORDC. Thus, the IMM's statements are not accurate. They are equivalent to saying that whenever the marginal unit providing energy changes that PJM is also changing the LMP calculation in those instances. Statements like these are based on a misunderstanding of the proposal.

Contrary to the IMM,[78] PJM's proposal is not "first and foremost" about energy market pricing. PJM's filing is focused on remedying the unjust and unreasonable reserve market design; changes to the LMP are due to the updated shape of the ORDC. As Drs. Hogan and Pope find, "[i]mplementation of [PJM's proposed] operating reserve demand curve and co-optimization to support both efficiency and consistent energy and reserve prices will translate into generally improved price signals for market participants."[79]

In short, PJM satisfies its FPA section 206 obligation in this case by showing that the current reserve market rules are unjust and unreasonable, as PJM has done in this proceeding. PJM can show that particular market rules are unreasonable

8. Parties arguing that winter 2019 experience did not reveal flawed reserve market are incorrect.

In the March 29 Filing, PJM illustrated the reserve market dysfunction by pointing out that, when the PJM region experienced extremely cold conditions this past January 30–31—an event that typically stresses system capabilities, reserve market prices "were $0/MWh for 29 hours of the 48-hour period, and were less than (and mostly

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[78] IMM Protest at 8.

[79] Hogan & Pope Reply at 8.

significantly less than) $10/MWh for 41 hours of the 48-hour period."[80] The Load Coalition attempts to downplay the significance of the market placing little to no value on reserves during such extreme weather conditions by arguing that the low prices are the result of "excess supply relative to demand."[81] But, the Load Coalition does not account for the underlying reason for such excess supply: operator bias.

Mr. Pilong explains that during the cold weather event on January 30–31, 2019, PJM operators biased the scheduled supply to ensure additional reserves were on the system.[82] To gauge the extent of the operator biases on those two days, Mr. Pilong compared the operator bias averages from the 2018 calendar year to those for January 30–31.[83] Mr. Pilong found that operators used much higher positive biases on January 30–31, indicating operators' desire for more generation and reserves which led to fewer shortage conditions.[84] In other words, PJM operators performed out-of-market actions to schedule extra supply, and therefore prices did not transparently reflect the core supply and demand fundamentals which signaled a need for more reserves.

9. Contrary to protests, reserve market uplift is substantial, relative to the size of the reserve market, and provided further evidence of the need for reserve market reforms.

A number of protestors argue that FPA section 206 action is not warranted because the dollar amount of uplift in the reserve market is not large, particularly when

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[80] March 29 Filing at 21. PJM also noted that "Hours less than $10 included two at $0.08, one at $0.63, one at $0.69 and one at $1.88 10-minute, non-synchronized reserve prices were $0 for 46 of the 48 hours." March 29 Filing at 21 n.30.

[81] Load Coalition Protest at 19.

[82] Pilong Reply Aff. ¶¶ 7-8.

[83] *Id.* ¶ 8.

[84] *Id.* Mr. Pilong determined the percentage of 5-minute intervals where the amount of Synchronized Reserves was less than the MRR (i.e., the Synchronized Reserves surplus was less than zero) with operators' positive bias removed to be 44.4%, and with both the positive and negative biases removed to be 42%. *Id.* ¶ 8, Table 1.

compared against energy market uplift or against changes in energy market revenues that could result from this filing.[85] The Commission should not be distracted by these comparisons. The significance of reserve market uplift should be assessed in relation to the reserve market. Reserve market prices send important signals to the market upon which future investment in reserve capability will be based, and regardless of the size of the market it is important that prices be well formed and reflective of supply and demand fundamentals and the value that reserves provide to the system.

Here, the current heavy reliance on uplift in the reserve market signals an unmistakable warning of dysfunction in the reserve market. As explained by Mr. Keech in his Reply Affidavit, barely over a third of reserve production costs were compensated through reserve market clearing prices; the remaining vast majority of production costs was compensated only through uplift.[86] A market that does not pay for nearly two-thirds of the costs to produce the product or service sold in that market is plainly not a well-functioning market.

Specifically, Mr. Keech shows that for 2018 almost half (46.2 percent) of the amounts paid for Tier 2 Synchronized Reserves came from uplift, instead of through market clearing price credits. Mr. Keech also shows that these market clearing price credits covered only about one-third (36.1 percent) of the production costs of providing Tier 2 Synchronized Reserves in 2018, with uplift providing the other 63.9 percent.[87] Thus, the current reserve market pricing fails to capture most of the costs incurred in providing synchronized reserves.

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[85] MdPSC Protest at 12; Load Coalition Protest at 25-27.

[86] Keech Reply Aff. ¶ 19.

[87] Keech Reply Aff. ¶¶ 19-20.

By any measure, 46 percent is an unacceptable share of service provider compensation to be provided through uplift. If that level of dependence on uplift were observed in any other market, it would be seen as a five-alarm fire demanding an immediate regulator response. To put the severity of these conditions in context, Mr. Keech demonstrates what PJM's energy market would look like if 46 percent of credits were paid through uplift, and 64 percent of production costs were compensated through uplift (as observed in the current reserves market).[88]

As he shows, PJM's energy market would look very different, as evidenced by the following summary table in his affidavit:

[88] Keech Reply Aff. ¶ 20.

Table 3: Summary of Outcomes from Hypothetical

	2018 Energy Market (billions)	Hypothetical 2018 Energy Market (billions)	Difference (Hypothetical minus 2018) (billions)	% Change
LMP Credits ($)	30.3	9.8	-20.5	68%
Uplift ($)	0.1	8.4	8.3	8300%
Total energy market billing ($)	30.4	18.2	-12.2	-40%
Energy Production Cost ($)	13.1	13.1	0	0%
Amount of production cost covered by LMP credits ($)	13	4.7	-8.3	-64%
Infra-marginal Rents[89] ($)	17.3	5.1	-12.2	-71%
LMP	$38.24/MWh	$12.39/MWh	$-25.85/MWh	-68%
% Production Cost paid through clearing price	99.2%	35.9%[90]	-63.3%	-64%
% of Production Cost paid through uplift	.8%	64.1%	63.3%	8297%
% Total credits paid through LMP	99.7%	53.8%	-45.9%	-46%
% Total credits paid through uplift	0.3%	46.2%	45.9%	13945%

As Mr. Keech concludes, if the same level of inefficiency that exists in the reserve market was found in the energy market, it would not be tolerated and would most certainly be found unjust and unreasonable. The fact that the reserve market is much smaller than the energy market and results in only $20 million in uplift as opposed to $8.4 billion does not make the price formation dynamics in the reserve market

[89] Infra-marginal rents are calculated as the difference between total energy market billing and production cost.

[90] Slight differences exist between the percentages shown here for the hypothetical energy market result and the original synchronized reserve market percentages upon which the example is based. This is due to rounding the figures throughout the example in order to simplify the numbers and make the example easier to digest.

acceptable.[91] Reserve market uplift is substantial relative to the size of the reserve market, and provides further evidence of the need for reserve market reforms.

B. Substantial Evidence Shows that the Current $850/MWh Penalty Factor Is Unjust and Unreasonable.

To ensure sufficient reserves, the market must be structured such that resources are indifferent to providing energy or reserves. In PJM's reserve market, the penalty factor defines the maximum price the system is willing to pay when the reserve level falls below minimum requirements. Accordingly, it "must be set to a level where the system would prefer to assign reserves to a resource with a high opportunity cost as opposed to violating the minimum reserve requirement and degrading reliability."[92] The March 29 Filing showed that, given the market rule changes since the current penalty factor was installed in 2012, $850/MWh is now too low to accomplish its objective and is unjust and unreasonable.[93]

Recognizing the changed circumstances since 2012, including allowing energy offers as high as $2,000/MWh to set LMP, PJM re-examined the penalty factor and found that "the lowest level that is consistent with the actions that system operators will take to maintain reserves and allow those actions to be reflected in market clearing prices . . . is $2,000/MWh."[94] PJM demonstrated that a penalty factor at this level is just and reasonable because, as Drs. Hogan and Pope conclude, it is "based on the maximum cost

[91] Keech Reply Aff. ¶ 28.

[92] Keech Initial Aff. ¶ 10.

[93] March 29 Filing at 28-33; Keech Initial Aff. ¶¶ 7-13; *see also* March 29 Filing at 50 ("Because PJM's current rules allow sellers to submit energy market offers that are eligible to set the LMP at price levels well in excess of $850/MWh, it follows that resources providing reserves can have opportunity costs at approximately the same level of the energy offers of the resources committed to maintain reserves. However, the current market rules prohibit the systematic commitment and pricing of these reserve resources due to the current penalty factor of $850/MWh.").

[94] Keech Initial Aff. ¶ 9.

at which resources could be procured based on market offers."[95] Indeed, a $2,000/MWh penalty factor enhances the integrity of the reserve markets' single clearing price by reducing the likelihood that resources will require out-of-market uplift payments to recover lost opportunity costs.[96]

While several commenters challenge whether PJM has demonstrated that the current $850/MWh penalty factor is unjust and unreasonable,[97] no party refutes that the penalty factor should be based on the opportunity cost of providing reserves instead of energy.[98] Indeed, several commenters recognized that the penalty factor should be based on opportunity costs, and that currently resources do face opportunity costs higher than $850/MWh to provide reserves instead of energy.[99] Since current resources do face opportunity costs higher than $850/MWh, it is essential for the penalty factor to be higher and reflective of the value so that market prices create the proper incentives and avoidance of out-of-market uplift.

For its part, the IMM states that "[i]f the goal is to ensure that all available reserves will clear before the market enters a shortage, the penalty factor should *exceed the largest possible lost opportunity cost* for a resource providing reserves instead of

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[95] Affidavit of Drs. William W. Hogan and Susan L. Pope on Behalf of PJM Interconnection, L.L.C., PJM ORDC Report at 16 (Exhibit 1 to Attachment C to the March 29 Filing) ("Hogan & Pope ORDC Report").

[96] March 29 Filing at 49-50.

[97] MdPSC Protest at 7-8; Load Coalition Protest at 26.

[98] The current $850/MWh penalty factor was set based on observed opportunity costs. *See PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057, at P 75 ("We note that the $ 850 per MWh reserve penalty factor is supported by historical evidence, i.e., by the maximum opportunity cost that has been paid to a generator providing reserves (an amount just over $ 850/MWh).").

[99] Load Coalition Protest at 65 (requesting the Commission consider a $1,000/MWh penalty factor which "reflects the highest opportunity cost that resources providing reserves in the PJM market would realistically face"); IMM Protest at 65.

energy."[100] In other words, the penalty factor should not be capped at a historical opportunity cost level; rather, it should be set to a level that captures expected opportunity costs. This is what PJM has proposed.

C. The March 29 Filing Demonstrated That PJM's Existing Two-Tier Synchronized Reserve Market Structure Is Unjust And Unreasonable.

In the March 29 Filing, PJM demonstrated that most resources that provide Synchronized Reserve are undercompensated in an unduly discriminatory manner.[101] PJM showed that the current structure undercompensates resources assigned to provide Tier 1 Synchronized Reserve relative to those providing Tier 2 Synchronized Reserve, even though both Tier 1 and Tier 2 provide the same 10-minute reserve product. Tier 2 gets paid and is subject to a performance-related penalty, while Tier 1 is generally not paid and never penalized for any underperformance.[102] PJM also showed that those undercompensated Tier 1 resources, which are relied on to provide reserves to maintain reliability, chronically fail to sufficiently respond to reserve shortage events. Such underperformance is not surprising, given that they face no penalty for failing to perform.[103]

While the IMM "supports the consolidation" of the Tier 1 and Tier 2 Synchronized Reserves into a single product,[104] with uniform commitment, compensation, and performance obligations to meet all Synchronized Reserve needs, the IMM nonetheless attempts to undercut one of the factual underpinnings demonstrating

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[100] IMM Protest at 65 (emphasis added).

[101] March 29 Filing at 5-6.

[102] March 29 Filing at 15-16.

[103] March 29 Filing at 15.

[104] Answer and Motion for Leave to Answer of the Independent Market Monitor, Docket Nos. EL19-58-000, et al., at 3 (May 31, 2019).

that the current two tier approach is unjust and unreasonable—unacceptably poor performance by Tier 1 Synchronized Reserve resources.[105]

The IMM asserts that PJM "mischaracterize[d] the response to spinning events" by determining the response rate only on PJM's estimate of Tier 1 present in its RT SCED software and not based on the resources that got paid for responding to a Synchronized Reserve Event.[106] However, the IMM's reliance on settlement data is misplaced; rather, data from RT SCED presents a more accurate measure of performance by resources PJM is relying on to provide Tier 1 Synchronized Reserve.[107] As the IMM acknowledges, the amount of Tier 1 Synchronized Reserves shown in RT SCED "incorporates PJM's deselection of units and modifications of units' physical parameters, especially ramp rates,"[108] and therefore RT SCED reflects the actual amount of Tier 1 reserves PJM is relying on to maintain reliability.[109]

The settlements data presented by the IMM do not reflect an accurate measurement of the resources available to provide Tier 1 Synchronized Reserve at the time of the event. In a Synchronized Reserve Event, PJM calls on all synchronized reserve resources to provide energy as soon as they can. However, *all* resources that increase their output following such a call receive Tier 1 credits associated with such MW increase, unless the resource had a Tier 2 Synchronized Reserve assignment. Even

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[105] IMM Protest at 19-21.

[106] IMM Protest at 19-20.

[107] The tables PJM presented in the March 29 Filing (at 18-19) showing the poor Tier 1 performance were copied and pasted directly from the IMM's State of the Market Reports for 2016-2018, where the IMM measured "Tier 1 Response Percent," presumably from RT SCED data.

[108] IMM Protest at 20.

[109] *See* Pilong Initial Aff. ¶ 24.

resources that are not assigned reserves and are simply being dispatched up for energy to meet increasing load receive Tier 1 credits.

In other words, the universe of resources receiving Tier 1 credits is far greater than the resources on which PJM was relying to provide Tier 1 Synchronized Reserve. The settlement construct of paying Tier 1 credits to all resources without a Tier 2 assignment that increase energy output is indifferent to whether PJM was actually relying on the resource to provide Tier 1 in RT SCED. In this way, the MWs receiving Tier 1 credits following an event can well exceed the MW of Tier 1 PJM believed was available, *and* resources PJM was relying on to provide Tier 1 still can substantially underperform.[110]

Properly placed into context, the data presented in the IMM's Protest show that resources PJM designated as providing Tier 1 Synchronized Reserve underperformed in every Synchronized Reserve Event since April 2018, with response rates below 50 percent in twelve of those twenty-one events.[111] Such performance rate is unacceptable by any measure. That resources designated to provide Tier 1 Synchronized Reserve do not respond at high rates to all events (and respond poorly in most) is unsurprising given their lack of compensation and lack of penalty for not responding.

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[110] For example, IMM Protest, Table 1 provides that 1,633 MW received Tier 1 credits in response to the April 12, 2018 Synchronized Reserve Event, well in excess of the 1,063 MW of Tier 1 estimated to be available at the time. IMM Protest at 21, Table 1. Table 1 also shows that only 591 MW of the estimated Tier 1 actually responded to the event—a 55.6 percent response rate. *Id.*; *see also* March 29 Filing at 19-20, Figure 4. This means that 1,042 MW of the compensated Tier 1 MW increase came from resources on which PJM was not relying to provide Tier 1. It is likely that much of that 1,042 MW response was simply responding to its energy dispatch instruction which could have been moving those resources up at the time to meet increased load or exports to neighboring control areas, or to respond to transmission constraints. Regardless, the salient fact is that the resources on which the system was relying to provide Tier 1 Synchronized Reserve had an unacceptably low response rate.

[111] IMM Protest at 21, Table 1.

III. CONTRARY TO PROTESTORS, PJM'S PROPOSED RESERVE MARKET RULE CHANGES ARE JUST AND REASONABLE.

A. Contrary To The Statements Of Certain Protestors, PJM's Reforms Will Incentivize The Development Of Flexible Resources, And Not Unreasonably Reward Inflexible Resources.

Contrary to the arguments raised by certain protestors, PJM's proposed reforms provide an incentive for flexible resources. As a threshold matter, reserve is inherently a ramping product, which values and rewards resources with the ability to quickly change output. On this basis alone, PJM's proposal incentivizes the development of flexible resources by ensuring that the PJM reserve market correctly values the ability to quickly change output, which it currently does not. The acknowledgment of this incentive is evidenced by the support of multiple commenters.[112]

Notwithstanding this reality, the IMM nonetheless states that the PJM-proposed ORDCs provide more benefits to inflexible resources than flexible ones and will create "a new source of revenue that delays the competitive retirement of inflexible capacity."[113] While the IMM's basis for this conclusion is not entirely clear, PJM believes that this concern originates from the fact that PJM's proposal will likely result in an increase in LMPs, and those LMPs will be paid to *all* resources providing energy—even those

[112]*See, e.g.*, Affidavit of Michael M. Schnitzer ¶ 11 ("Schitzer Aff.") ("[I]mplementation of PJM's proposal will improve energy and reserve pricing and provide better incentives for capital investment that increases flexibility in both supply and demand.") (The Schnitzer Aff. is attached to the Comments of Exelon Corporation, Docket Nos. EL19-58-000, et al. (May 15, 2019)); Comments of Vistra Energy Corp. and Dynegy Marketing and Trade, LLC, Docket Nos. EL19-58-000, et al., at 6 (May 15, 2019) ("[T]he downward-sloping ORDCs based on measured forecast uncertainty will send transparent market signals for asset owners to invest in the flexibility needed to maintain reliability."); Comments of the Energy Trading Institute, Docket Nos. EL19-58-000, *et al*., at 6 (May 15, 2019) ("ETI supports the proposed shape of the ORDC curve and the annual modifications to the curve. Such modifications will reduce uncertainty and incentivize development of flexible resources."); PSEG Companies Supporting Comments and Limited Protest to PJM Interconnection, L.L.C.'s Proposal for Enhanced Price Formation in PJM Reserve Markets, Docket Nos. EL19-58-000, *et al*., at 5 (May 15, 2019) ("[T]he enhancements will provide more robust price signals for fostering resource flexibility which will facilitate higher levels of penetration by renewable resources.").

[113] IMM Protest at 47-49.

inflexible resources that are not capable of providing reserves. The IMM's inference is that this is a flaw that correspondingly renders PJM's proposal unjust and unreasonable. While the Commission recently rejected a similar argument made by the IMM in its April 2019 Fast-Start Pricing Order,[114] PJM will address the IMM's concerns separately here.

The concept of increasing LMPs when the supply of reserves tightens is not new, and is a foundational principle underlying basic energy market design elements proposed *by the Commission* like shortage pricing, which is used not only in PJM but in other RTOs/Independent System Operators ("ISO"). In Order No. 719,[115] the Commission listed an ORDC as one of the four potential approaches that an RTO/ISO could adopt to ensure that the market price for energy accurately reflected the value of such energy during an operating reserve shortage,[116] and noted that the California Independent System Operator, MISO, New York Independent System Operator, Inc., and ISO New England, Inc. had all represented in the rulemaking that they had adopted, or were soon going to adopt, an ORDC in compliance with Order No. 719.[117] As Mr. Keech fully explains in his Reply Affidavit, the claim that this rational market clearing outcome of raising energy prices when reserves are scarce somehow specifically incentivizes inflexibility is

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[114] *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,058, at P 54 (2019) ("We also disagree with the PJM Market Monitor that fast-start pricing is likely to result in generation owners with a portfolio of resources inefficiently keeping inflexible units in the market. The PJM Market Monitor appears to be noting, among other things, that the ability of a fast-start resource to set prices – and to benefit its affiliated flexible resources with those higher prices – would create an incentive for a generation owner to not retire inflexible fast-start resources, even when market fundamentals would otherwise support retiring those resources. We disagree. Such a strategy would seem particularly speculative and risky to the generator owner. The benefit to such a generator owner in keeping one additional inefficient generator online is likely to be negligible, while the risk of not retiring an inefficient resource when market fundamentals support retiring it would be considerable.").

[115] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[116] *Id*. at P 234.

[117] *Id*. at P 176.

erroneously predicated on (1) the IMM's incorrect assumption that Case A is the appropriate base case for measuring the impact of PJM's proposal, and (2) the IMM's failure to consider the scale of the energy market when compared to the reserve market.[118]

Moreover, while the IMM's definition of "flexible" in its analysis is unclear, PJM considers flexible resources in the context of this proceeding to be those resources that are capable of providing some kind of reserve product that PJM needs, meaning that the resource has a dispatchable range and, when called upon, is capable of providing energy within 10 or 30 minutes (depending on the product). Mr. Keech demonstrates that the IMM's own analysis shows that flexible resources (under PJM's reasonable definition) will receive between 65.3% and 76.5% of the total revenue increase resulting from PJM's proposal.[119]

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[118] *See* Keech Reply Aff.¶ 15. Mr. Keech notes that "[i]n the analysis I provided in my Initial Affidavit, I estimated an increase in energy market revenues of $366 million and an increase in reserve market revenues of $189 million. While the energy revenue increase is higher than the reserve market increase, it is important to keep in mind the scale of these two markets. The PJM energy market settles roughly 800,000 gigawatt hours ("GWh")/year, while the reserve market under the PJM Proposal would settle about 50,000 GWh/year. In short, the energy market is about sixteen times larger than the reserve market. Therefore, in a simplistic view, any price change in the energy market will generate sixteen times the amount of revenue that the same price change would create in the reserve market. For this reason, it is more appropriate to consider these changes on a percentage basis to gauge the impact of design changes, as it normalizes the sizes of the markets. When considering the PJM Proposal in this manner, the increase in energy market revenues is estimated to be 1.31% ($366 million) and the estimated increase in reserve market revenues is 404% ($189 million)."

[119] Mr. Keech notes that "the IMM compares Case B to Case C to show the revenue increase and decrease by technology type. If the total change in energy and reserve revenues is summed across all asset types that collected some amount of reserve revenues (i.e., the sum of the change in total revenues for each asset class where the increase in reserve revenues increase is greater than zero), then approximately 76.5% of the total revenue increase is paid to flexible units. If the same simple analysis is performed on Table 19, which is the IMM's inappropriate comparison between Case A and Case C as the impact of the PJM Proposal, it still shows that 65.3% of the total revenue increase goes to resources that are flexible and providing reserves under the PJM Proposal." *See* Keech Reply Aff. ¶ 16.

Lastly, the data referenced by the IMM[120] shows nothing more than that energy market revenue increases will be spread among resource types in a manner that reflects the resource portfolio composition at the time of the historic "snapshot." The correct focus should instead be on the resource *qualities* that will be better compensated by improved reserve market pricing.

In further support of the conclusion that PJM's reforms will incentivize the development of flexible resources, PJM refers to the report titled *Rewarding Flexibility: An Analysis of the Impact of PJM's Proposed Price Formation Reform on the Incentives for Increasing Generator Flexibility*, by Professor Mort Webster of the Pennsylvania State University ("Webster Report"), designated as Attachment E hereto. This report examines PJM's proposed changes to the ORDCs and the addition of the 30-minute reserves, and assesses the relative impacts of these changes on the financial incentives for natural gas combined cycle generators to invest in technology to increase the flexibility of their plants. The analysis simulated the ERCOT for the year 2016, superimposing the current PJM ORDCs and then PJM's proposed ORDCs, and calculated the system costs, net revenues to each generator, and other metrics.[121] The simulations were then repeated where one combined cycle generator receives a hypothetical upgrade to increase its flexibility. Under the analysis, the change in net revenues to the owner of the upgraded generator offers a way to quantify the (dis)incentive to invest in flexibility, and the comparison of this metric between the two reserve market designs provides a way to

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[120] IMM Protest at 49, Table 3.

[121] The report notes that "[t]he data to model the PJM grid with the precision necessary to be informative was not available within the desired time frame," and accordingly the analysis relied upon the pre-existing ERCOT model. Webster Report at 4. The particular underlying RTO system model that PJM's proposed ORDCs are superimposed onto does not have a significant impact on the ultimate conclusions reached in the report.

assess whether the proposed reserve market design improves or weakens the incentive for flexibility.[122]

The report concludes that "the results of the analysis strongly suggest that the proposed changes to the reserve market by PJM would in fact increase the incentives to invest in most types of flexibility,"[123] and that "[u]pgrades to increase the maximum output, decrease the minimum output, increase the ramp limit, and combinations of all features would lead to a greater increase in net revenues (a proxy for generator profit) under the proposed design, as compared with current reserves."[124]

B. *Notwithstanding The Protests, The Commission Has Substantial Evidence To Find That PJM's Proposed ORDC Methodology Is Just And Reasonable.*

1. *Contrary to protestors, PJM's proposed look-ahead periods to estimate forecast error are reasonable.*

PJM's ORDC methodology uses resource and load forecast errors to help define the probability that PJM could fall short of the MRR. The forecast errors are measured by comparing a forecast value with an actual realized value. For this purpose, PJM considers the forecast (in the case of 10-minute reserves) that occurred 30 minutes before the actual value.

Some parties challenge PJM's selection of a 30-minute look-ahead period, and urge the Commission to direct PJM to use instead a 15-minute or 20-minute look-ahead period[125] These changes, by reducing the time between forecast and actuals, would tend

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122 Webster Report at 1.

123 *Id*.

124 The report does find that "[o]nly the incentive to invest in a faster startup time [sic] is not improved by the proposed market change." *Id*.

125 *See, e.g.*, IMM Protest at 33-38; Comments of Old Dominion Electric Cooperative on Reserve Price Formation Proposal, Docket Nos. EL19-58-000, et al., at 10-11 (May 15, 2019) ("ODEC Comments").

to reduce the forecast error assumed for the ORDC, and thus reduce the probability of falling short of the MRR, for which the ORDC must procure reserves. All else equal, lower probabilities translate into lower prices on the ORDC. However, if the probabilities used to design the curve are reduced to the point that they fail to account for actual load and resource uncertainties, then the sloped part of the ORDC will be less successful in achieving its objective of procuring sufficient reserves to avoid falling below the MRR. The IMM and ODEC proposals to use, respectively, 15-minute or 20-minute look-ahead periods, fall short in this respect, because they do not account for the time that can elapse between when PJM runs the forecast for the RT SCED case (i.e., the time of the forecast), and when the scheduled resource has to perform (i.e., the occurrence of the event being forecasted). Assuming away part of the time period between the forecast and the event may seem to reduce the probability of error, when in fact it is merely a choice to ignore some of the actual probability of error. By contrast, PJM's 30-minute look-ahead period fully captures the time that can elapse between the RT SCED forecast and the actual reserve performance, and thus is a reasonable metric for the uncertainties used to design the ORDC.

Specifically, as Dr. Rocha Garrido explains in his Reply Affidavit, "the length of the interval between the solution of the RT SCED case and the end of the period in which the procured reserves are expected to respond in case they are deployed is at least 20 minutes: (T+10) – (T-10)."[126] That 20-minute minimum thus is the sum of: (i) the 10-minute minimum time from the RT SCED forecast to the target time; plus (ii) the 10 minutes Synchronized Reserve resource has to respond. But the time lapse can exceed

[126] Rocha Garrido Reply Aff. ¶ 29 (quoting Rocha Garrido Initial Aff. ¶ 13).

that 20-minute minimum because "forecast models must be run before RT SCED cases (and the forecast models are run only every 5 minutes)."[127] Consequently "the [forecast] inputs used in some RT SCED cases targeted for a time T are from T-15 or even T-20."[128] Adding those times between the forecast and the target to the time allowed for the reserve response "produces a look-ahead period of 25 minutes ((T+10) – (T-15)) or even 30 minutes ((T+10) – (T-20)) for some RT SCED cases."[129]

PJM's 30-minute look-ahead therefore is reasonable, whereas "[t]he ODEC and IMM proposals for only a 15 or 20 minute look-ahead period therefore would not capture the elapsed time in all cases between [the forecast for] the RT SCED run and the deadline for the scheduled reserves' response."[130]

2. Contrary to the Load Coalition, $10/MWh is not a reasonable price for all reserves procured above the MRR.

Mr. Wilson, appearing for both the Load Coalition and CEA, contends that PJM's proposed ORDC violates the ORDC design principles developed by Drs. Hogan and Pope, including PJM's alleged lack of a "Security Minimum," and failure to base the ORDC on the Value of Lost Load ("VOLL").[131] Mr. Wilson then alleges that if PJM based its ORDC on values of the Security Minimum and VOLL estimated by Mr. Wilson,

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[127] Rocha Garrido Reply Aff. ¶ 29.

[128] *Id.*

[129] *Id.*

[130] *Id.* Dr. Rocha Garrido further demonstrates this point by illustrating how an ORDC designed with only a 15-minute look-ahead period, as proposed by the IMM, would ignore the probability of events occurring after the end of the fifteen minutes, but before the deadline for the reserves to respond, and thereby understate the probabilities of falling short of the MRR. *Id.* ¶ 30.

[131] Affidavit of James F. Wilson in Support of the Protest of the Clean Energy Advocates ¶¶ 27-36 ("Wilson CEA Aff."). The Wilson CEA Aff. is attached to the Protest of Clean Energy Advocates, Docket Nos. EL19-58-000, et al. (May 15, 2019) ("CEA Protest").

the marginal value of incremental operating reserves at the MRR point would be only $10/MWh.[132]

The Commission should not credit this analysis. First, as Dr. Hogan and Pope affirm, in the PJM context, the MRR "is the logical equivalent to the basic concepts in the Hogan and Pope prior discussion of 'Security Minimum.'"[133] As they explain, "the objective is to determine prices that reflect operator actions;" and, for PJM, "the MRR defines the level where the system operator would begin to take emergency actions ex ante to provide the level of reserves before the start of the dispatch interval."[134] Therefore, "the MRR is the appropriate reference point for setting the price equal to the costs of those emergency actions."[135] This explanation by Drs. Hogan and Pope therefore negates Mr. Wilson's critique of PJM's ORDC for allegedly falling short of the Hogan and Pope ORDC design principles.

Moreover, Dr. Rocha Garrido shows in his Reply Affidavit that Mr. Wilson's alternative ORDC reserve price estimate is not supported by quantitative analysis.[136] As he explains, such an ORDC-based reserve price estimate requires an estimate of the security minimum as well as "a probabilistic distribution for the net–load error are required (so that the probability of falling below the Security Minimum when the quantity of reserves is equal to the MRR can be calculated)."[137] However, Mr. Wilson supplies neither of these values; and "relies instead on a 'rough' loss of load probability

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[132] Wilson CEA Aff. ¶ 30.

[133] Hogan & Pope Reply at 9-10.

[134] *Id.* at 9 (footnote omitted).

[135] *Id.*

[136] Rocha Garrido Reply Aff. ¶ 24.

[137] *Id.*

estimate of 0.001 based on his claim that 'system operators have generally been comfortable with the MRR.'"[138] However, as Dr. Rocha Garrido notes, "it is incorrect to conclude that system operators have generally been comfortable with the MRR",[139] given that "system operators have regularly procured additional reserves *in excess* of the MRR based on their ongoing assessments of uncertainty."[140] Therefore, Mr. Wilson's extremely low estimate of the ORDC reserve price should be rejected.

3. Contrary to ODEC, PJM's proposed ORDC does not produce prices that are "out of bounds."

Similarly, ODEC claims to have run PJM's ORDC values through the Hogan-Pope VOLL method and concluded that PJM's ORDC values are "out-of-bounds,"[141] However, ODEC's calculations are incorrect. As shown by Dr. Rocha Garrido,[142] ODEC's calculation ignores Drs. Hogan and Pope's acknowledgement that their approach can accommodate an "extension to include minimum contingency reserves (i.e., the Minimum Reserve Requirement)."[143] Consistent with this acknowledgement from the leading experts on an ORDC, PJM's proposed ORDC includes a Minimum Reserve Requirement. However, by ignoring that guidance from Drs. Hogan and Pope, the particular formula ODEC chose to employ applies only when *there is no* MRR. Dr. Rocha Garrido then demonstrates the correct interpretation of the PJM data cited by ODEC, in a manner consistent with the formula Drs. Hogan and Pope presented in their report appendix for applying their ORDC principles in an MRR context. As he shows,

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[138] *Id.* (quoting Wilson CEA Aff. ¶ 30).

[139] Rocha Garrido Reply Aff. ¶ 24.

[140] *Id.*

[141] ODEC Comments at 6-7.

[142] Rocha Garrido Reply Aff. ¶ 25.

[143] Hogan & Pope ORDC Report at 16.

the resulting calculated probability of falling below the MRR is perfectly in line with PJM's three years of historic data.[144] ODEC's conclusion that PJM's proposed ORDC produces results that are "out-of-bounds" therefore is discredited.

4. *The ORDC should price reserves at the penalty factor when the quantity of reserves is less than the MRR. Considering the probabilities for each of the primary sources of uncertainty is a reasonable approach, and is not overly conservative.*

The IMM argues that PJM's forecast error method of constructing the probabilities used in the ORDC is overly conservative, because forecasts can be wrong in both directions, and thus prevent rather than create shortages.[145] However, as Dr. Rocha Garrido explains, "[r]elying on the possibility that the forecast error may be in PJM's favor to avoid an ex-post MRR shortage in order to price reserve quantities below the MRR, as suggested by the IMM, would dampen [the] strong price signal [required when reserves fall below the MRR]."[146] As Dr. Rocha Garrido elaborates, while "there is a non-zero probability that the MRR is met ex-post even if there is an ex-ante MRR deficiency," if one used this non-zero probability to develop the ORDC, "then reserve prices associated with quantities below the MRR would be below the penalty factor," given the "non-zero chance that the net-load forecast error will turn out in PJM's favor."[147] But that result, i.e., setting the reserve price when PJM is experiencing a reserve shortage at less than the penalty factor, "is inconsistent with operating the grid securely and reliably."[148] Indeed, under the IMM's premise, "the price associated with a

[144] Rocha Garrido Reply Aff. ¶ 26.

[145] IMM Protest at 38-40.

[146] Rocha Garrido Reply Aff. ¶ 15.

[147] Rocha Garrido Reply Aff. ¶ 14.

[148] *Id.*

quantity of reserves equal to 0 MW would be less than the penalty factor, even though at that point PJM operators would be executing emergency operating procedures that are likely to have a cost greater than the penalty factor to create reserves."[149]

5. *Considering the probabilities for each of the primary sources of uncertainty is a reasonable approach, and is not overly conservative.*

The Load Coalition's affiant Mr. Griffey argues that PJM does not account for the fact that some of its forecast errors may be negatively correlated, and thus offsetting rather than additive.[150] This criticism reveals a misunderstanding of PJM's proposal. Careful review of the formula in Dr. Rocha Garrido's Initial Affidavit shows that *all* correlations between the uncertainties—whether negative positive, or no correlation—are captured by the net-load error empirical distribution, which is the data ultimately used to construct the PJM ORDCs.[151]

6. *Protestors misunderstand or mischaracterize PJM's proposed use of "Expected Value" and historic error data in PJM's proposed ORDC methodology.*

The Load Coalition contends that PJM proposed ORDC methodology uses the concept of "expected value" to calculate the incremental value of reserves in excess of the MRR, where, expected value refers to the "'weighted average outcome of a given decision when all possible outcomes are considered' based on probability."[152] The Load

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[149] *Id.* ¶ 15.

[150] Load Coalition Protest at 41-43; Affidavit of Charles S. Griffey on Behalf of the PJM Load/Customer Coalition ¶¶ 9-11 ("Griffey Aff.") (Attachment B to Load Coalition Protest).

[151] Rocha Garrido Reply Aff. ¶ 16.

[152] Load Coalition Protest at 41 (emphasis omitted).

Coalition then criticizes what it perceives to be "the use of averages" as "not an appropriate means to set prices."[153]

The Load Coalition's criticism is unsupported and incorrect. As Dr. Rocha Garrido explains, "[e]xpected value is an appropriate concept to use when dealing when uncertain outcomes that depend on probabilities."[154] Expected value is an appropriate concept here because "when procuring reserves above the MRR, there is both: (1) a probability that such reserves *will* be enough to avoid an MRR deficiency, thus avoiding triggering the penalty factor; *and* (2) a probability that such reserves *will not* be enough to avoid an MRR deficiency."[155] Consequently, "[t]he calculation of the value of reserves above the MRR must consider the probabilities and outcomes under" both these scenarios."[156] "Expected Value" therefore "provides a way to consider such probabilities and outcomes to establish the value of reserves, which result in the mathematical formula employed to derive the downward-sloping section of the ORDC proposed by PJM."[157] This application of the concept of expected value also is consistent with the principles outlined by Drs. Hogan and Pope.[158]

The Load Coalition's affiant Mr. Griffey exhibits a similar misunderstanding. In response to his testimony alleging that PJM is using three-year average forecast errors as proxies for actual change in reserves to construct the ORDCs,[159] PJM confirms that this is not part of the proposal. Rather, as Dr. Rocha Garrido stated in his Initial Affidavit, PJM

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[153] *Id.*

[154] Rocha Garrido Reply Aff. ¶ 17.

[155] *Id.*

[156] *Id.*

[157] *Id.*

[158] *See* Hogan & Pope Reply at 5-6.

[159] Load Coalition Protest at 40-41; Griffey Aff. ¶ 7.

is proposing to combine error data and Regulation Requirement data *point-by-point* to derive a net-load error probabilistic distribution.[160] In his Reply Affidavit, Dr. Rocha Garrido refers again to the detailed formula set forth in his initial affidavit which prescribes how the data is combined to arrive at the actual change in reserves over the specified time interval, adjusted for the regulation requirement.[161]

7. Contrary to protestors, PJM's proposed ORDC will not over-procure reserves.

A few commenters raise issue with the amount of reserves that would be procured under PJM's proposed ORDC, claiming that PJM would procure thousands of MWs of reserves in "excess" of the minimum reserve requirements.[162] However, as fully explained above, the Commission has found that the amount of reserves needed is not limited by the minimum reserve requirement. As a result, procurement of reserves in excess of the MRR does not necessarily result in procurement of "excess" reserves. Rather, so long as there is an objective demand for reserves beyond the minimum requirements, such reserves are needed.

PJM has established such demand here. As demonstrated in the March 29 Filing[163] and in this answer,[164] the quantity of reserves that would be procured with the new ORDCs is a function of a probabilistic analysis of the operational uncertainties PJM expects to face based on actual forecast errors experienced in the prior three years during that time of the day and during that season. As Dr. Rocha Garrido explained in his Initial

[160] Rocha Garrido Initial Aff. ¶ 15(c).

[161] Rocha Garrido Reply Aff. ¶ 16.

[162] Comments of American Electric Power Service Corporation, Docket Nos. EL19-58-000, et al., at 5-6 (May 15, 2019) ("AEP Comments"); Load Coalition Protest at 22-25.

[163] March 29 Filing at 57-58; Rocha Garrido Initial Aff. ¶ 15.

[164] *See supra* Sections IV.B.1-6; Rocha Garrido Reply Aff. ¶ 16.

Affidavit, PJM developed very granular ORDCs to capture the specific conditions present at different times of the day and likelihood of the various load, wind, and solar forecast and generator outage uncertainties for such time of day.[165]

Dr. Rocha Garrido adds in his Reply Affidavit that these claims of over-procurement "are mere assertions, reflecting judgments that there is no uncertainty in reserve levels beyond some arbitrary point, or that the value of reserves in reducing the uncertainty that does exist should simply be ignored."[166] In contrast to these unsupported assertions, "PJM's proposed ORDCs are based on quantified real-time uncertainties" which have in fact "historically reached large magnitudes," even exceeding one thousand MWs, as Dr. Rocha Garrido shows.[167] While the probability of these large uncertainties is low, it is greater than zero. Therefore, "trim[ming] the ORDCs at a point other than when the probability of falling below the MRR is zero," as proposed here by protestors, "would constitute a design choice to deem the probability of experiencing large magnitude net-load errors to be zero, notwithstanding historical data showing otherwise."[168]

By using probabilities to forecast errors affecting the need for reserves, the amount of reserves procured is anchored in actual data and realities that PJM operators have to take into account. Those uncertainties will only increase over time, as demonstrated in PJM's original filing, as the profile of the fleet changes.

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[165] Rocha Garrido Initial Aff. ¶¶ 8-11.

[166] Rocha Garrido Reply Aff. ¶ 21.

[167] *Id.* ¶ 22 & Table 1.

[168] *Id.* ¶ 22.

C. PJM's Proposed $2,000/MWh Penalty Factor Is Just And Reasonable.

While many parties oppose PJM's proposal to raise the penalty factor to $2,000/MWh, they appear to support increasing the penalty factor to $1,000/MWh, increasing in "$250 per MWh increments for market hours when PJM approves short run marginal costs over $1,000 per MWh, such that the penalty factor exceeds the highest short run marginal cost in the market."[169] MdPSC attempts to argue that PJM failed to demonstrate $2,000/MWh is just and reasonable because "PJM has not reported any significant events where energy prices exceeded $1,000/MWh and reserve prices did not respond as expected."[170] Other comments similarly suggest that because energy prices do not often exceed $1,000/MWh, the penalty factor should not be set at $2,000/MWh.[171]

However, these arguments miss the point. The fact is that resources *can* face an opportunity cost well above $1,000/MWh, up to $2,000/MWh or higher. While PJM recognizes that "this scenario is not likely . . . it can happen and system operators are required to take actions in this price range to maintain reserves."[172]

It is important to understand that the marginal cost of producing energy is not the only determinant of the level of the lost opportunity cost a resource will incur by providing reserves instead of energy. Lost opportunity cost is a function of the difference between LMP and a resource's energy market offer. Because LMP (i.e., the marginal cost of serving the next increment of load) is the sum of the short-run marginal cost of the resource that can serve the next load increment, marginal line losses, and the cost of

[169] IMM Protest at 65; *see also* AEP Comments at 5; ODEC Comments at 7-10; Load Coalition Protest at 68.

[170] MdPSC Protest at 8.

[171] Load Coalition Protest at 50-52.

[172] Keech Initial Aff. ¶ 10.

transmission congestion, lost opportunity cost accounts for present congestion and losses. PJM illustrates below the extent to which lost opportunity costs, when congestion rents are included, exceed $1000/MWh.[173] Therefore, the reserve penalty factor should not be set purely based upon the energy market offer cap and must consider the levels of lost opportunity cost that can be created when LMPs rise.

For example, if a transmission constraint is binding at the $2,000/MWh transmission constraint penalty factor and a resource has a 50 percent distribution factor on the constraint, the congestion contribution to that resource's LMP is $1,000/MWh. Assuming no other constraints are binding, the impact of marginal losses is minimal, and the marginal cost of energy is $300, that resource will have a total LMP of $1,300/MWh. If the resource's incremental energy offer is $150, then it means the resource would incur a lost opportunity cost of $1,150/MWh if committed to provide reserves. Thus, although energy market offers are almost always below $1,000/MWh, LMPs, and therefore lost opportunity costs, can rise above $1,000/MWh as noted above, because of congestion (and to a much lesser extent transmission losses).

Indeed, a review of all the LMPs and energy and Synchronized Reserve offers for period from January 1, 2014, through April 30, 2019, shows that lost opportunity costs, which constitute the bulk of the offers used in forming the Synchronized Reserve supply stack, exceeded $1,000/MWh on 3.6 percent of the days (70 of 1,947 days). Further, such days have become more frequent since PJM began allowing transmission constraint penalty factors of up to $2,000/MWh to set the shadow price of a constraint and therefore

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[173] March 29 Filing at 48-49.

impact congestion prices.[174] Only in a small portion of the intervals with lost opportunity costs in excess of $1,000/MWh was the PJM system experiencing a reserve shortage—meaning that only in a handful of intervals were the $300/MWh or $850/MWh reserve penalty factors affecting LMPs and therefore the resulting lost opportunity costs of providing reserves. Finally, lost opportunity costs exceeded $2,000/MWh in eight percent of these intervals, demonstrating that, while infrequent, resources could face opportunity costs of $2,000/MWh or greater when providing reserves over energy.

The Load Coalition attempts to sideline these facts by asserting that only "legitimate" opportunity costs should be considered, and "a particular energy price level cannot constitute a legitimate opportunity cost for a generation resource if that price level is rarely—or never—available to that resource."[175] But, the likely infrequency of being in a reserve shortage while overall opportunity costs are at or near $2,000/MWh does not make accounting for such a possibility unjust and unreasonable. To the contrary, planning for such events is appropriate to ensure that: (1) PJM's energy and reserve market prices accurately reflect the cost of meeting the system's energy and reserve needs (to the greatest extent possible); and (2) PJM's clearing algorithms select the least-cost solution.

If the penalty factor is set too low, resources that may be available to prevent or resolve a shortage may not receive a reserve assignment if their opportunity cost is greater than the penalty factor. For this reason, the Commission found that "[i]f reserve penalty factors are set too low, however, the system will go short for economic

[174] *See PJM Interconnection, L.L.C.*, 166 FERC ¶ 61,015, at PP 7, 24 (2019) (accepting, effective February 1, 2019, energy market rules that "allow the transmission constraint penalty factor to set the marginal value [of congestion] for a transmission constraint").

[175] Load Coalition Protest at 50.

reasons."[176] Indeed, "market prices may create the appearance of a reserve shortage even where the actual operating conditions would reflect the availability of sufficient reserves to meet the reserve requirement."[177] What is more, in these circumstances, resources will be priced outside the market on an individual unit basis and the clearing price would signal a shortage even though resources able to provide reserves were available.

D. Allowing Energy And Reserve Prices To Reflect The Independent Value Of Each Reserve Shortage Currently Facing The System Is Just And Reasonable.

Several commenters object to PJM's proposal to remove the existing artificial cap on prices for energy and reserves during a shortage event and allow for energy and reserve prices to reflect each penalty factor for each reserve product in each reserve zone that is in shortage.[178] Specifically, the market rules currently cap the energy component of LMP during a shortage event to $3,700/MWh, a price equal to the sum of the energy offer cap and two reserve penalty factors ($2,000/MWh + $850/MWh + $850/MWh),[179] and under PJM's proposal energy and reserve prices could reach $12,000/MWh.[180] Commenters opposing PJM's removal of the price cap do not challenge the concept of adding penalty factors and the energy price to incentivize resources to provide the needed

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[176] *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057, at P 72.

[177] *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057, at P 72.

[178] Load Coalition Protest at 53-54; IMM Protest at 31; ODEC Comments at 11-12.

[179] *See* Operating Agreement, Schedule 1, section 2.5(b); *see also PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057, at P 19 ("PJM therefore proposes to set a maximum energy price of approximately $ 2,700 per MWh, the price that would result from energy and two reserve products reaching their caps . . . .").

[180] This is the sum of the energy price cap of $2,000/MWh plus the five $2,000/MWh penalty factors for falling below: the Minimum Synchronized Reserve Requirement in the RTO Reserve Zone and the Mid-Atlantic-Dominion ("MAD") Reserve Zone; the Minimum Primary Reserve Requirement in the RTO Reserve Zone and the MAD Reserve Zone; and the Minimum 30-minute Reserve Requirement in the RTO Reserve Zone.

reserves and energy.[181] They simply contend that a price of $12,000/MWh is per se too high, even when the PJM system does not have enough reserves to meet *any* of its minimum reserve requirements.

However, allowing prices to rise to reflect the independent value of each reserve shortage currently facing the system is just and reasonable. As Drs. Hogan and Pope explain, PJM's approach "reflects the hierarchy of several types of reserves and is used to construct additive requirements for nested operating reserve zones within PJM."[182] This approach, they find, "allows for a simpler implementation and more closely follows the current reliability practice embedded in system operations in PJM."[183] As a result, PJM's approach provides a "workable approximation of the value of operating reserves of different types and in different places given PJM's proposed implementation in its co-optimized dispatch" and in a manner that "will be easier to implement and maintain."[184]

Further, PJM's proposal is consistent with PJM's current practice, and consistent with the Commission's price formation objectives of clearing prices that reflect the cost of serving load.[185] While prices may rise to this level only in the unlikely event that there is a "simultaneous occurrence and confluence of multiple product and locational shortages,"[186] that does not mean that prices should never reach it. Such prices would signal the "very extreme conditions that demand immediate supplier response," and

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[181] Indeed, "ODEC understands the academic nature of this displacement argument." ODEC Comments at 11.

[182] Hogan & Pope Reply at 8.

[183] Hogan & Pope Reply at 8.

[184] Hogan & Pope Reply at 8.

[185] *See, e.g., PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,058, at P 35 ("We continue to find that fast-start pricing in PJM, with the reforms directed herein, will result in prices that more accurately reflect the marginal cost of serving load.").

[186] March 29 Filing at 12.

"approximate[] consensus estimates of the value to load of avoiding curtailment"[187] and therefore would properly incentivize demand to curtail or generation to provide energy or reserves in a timely manner. Further, to the extent the markets ever reach such prices, they would incent new or modified generation resources (or demand response resources) flexible enough to capture such prices.[188] By contrast, not "allow[ing] for prices to rise sufficiently during an operating reserve shortage to allow supply to meet demand [is] unjust, unreasonable and may be unduly discriminatory[.]"[189] That is because capping energy and reserve prices too low "may not produce prices that accurately reflect the value of energy and, by failing to do so, may harm reliability, inhibit demand response, deter entry of demand response and generation resources, and thwart innovation."[190]

E. Establishing a Single Synchronized Reserve Market and Paying All Resources Assigned to Provide Synchronized Reserve the Market Clearing Price Is Just and Reasonable.

Several parties assert that it is just and reasonable to not compensate resources for providing Tier 1 Synchronized Reserve, because they have "no opportunity costs associated with providing" Tier 1 given that they are already online, generating energy, but not fully loaded.[191] However, these arguments are incorrectly focused on the resource and not the product or the market. A market cannot function efficiently if the sellers of the product have no incentive to actually provide it. That is the case with Tier 1

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[187] March 29 Filing at 12.

[188] *See PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057, at P 74 (The Commission found that allowing energy and reserve prices to extend beyond the energy market price cap "will encourage responsive actions by market participants that will lessen the extent of the shortage and signal investment in both demand response technology and generation, thus minimizing the economic harm of future shortages. Specifically, higher clearing prices will encourage customers to reduce their consumption, or encourage the owners of resources that may be shut down due to forced outages to bring their resources back online faster.").

[189] *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057, at P 70.

[190] *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057, at P 71.

[191] Load Coalition Protest at 22; *see also* MdPSC Protest at 4; IMM Protest at 56-57.

Synchronized Reserves. Resources assigned to provide synchronized reserves (whether Tier 1 or Tier 2) are relied on to provide those assigned MWs of energy within ten minutes of being called upon by PJM. Yet, PJM cannot rely on resources with Tier 1 assignments because they have no incentive to perform (i.e., their Tier 1 assignment comes with no guaranteed compensation[192] and no penalty for non- or under-performance). The natural resolution to this is to re-design the market to procure a single product, with uniform commitment, compensation, and performance obligations, which is what PJM has proposed.

PJM has proposed a unified, single-clearing price market to procure Synchronized Reserves. Like all single-clearing price markets, all resources assigned to provide Synchronized Reserves will receive the market clearing price regardless of their opportunity costs. The cost of the marginal unit assigned to provide reserves will set the clearing price. PJM's energy market is structured in the same way, and operates efficiently in this manner. There, resources with zero incremental cost (like some wind resources) are dispatched and paid LMP. The market pays the marginal unit's cost.[193] This is just and reasonable. Similarly, it is just and reasonable to pay Synchronized Reserves via a single clearing price, based on the marginal unit's cost of providing such reserves, regardless of whether a resource's opportunity cost is zero.[194]

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[192] Under the current rules, resources are compensated for their Tier 1 assignments only when the Non-Synchronized Reserve Market Clearing Price rises above zero dollars. At those times, Tier 1 resources receive the Tier 2 Synchronized Reserve Market Clearing Price. Tariff, Attachment K-Appendix, section 3.2.3A(b)(i).

[193] And, just like the energy market, when the opportunity cost of a resource assigned to provide reserves exceeds the clearing price, the resource will be eligible for a make-whole payment, via uplift. *See* March 29 Filing at Attachment A, proposed Tariff, Attachment K-Appendix, section 3.2.3A(f)(iii).

[194] *See PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at P 195 (2007); *Cal. Indep. Sys. Operator Corp.*, 112 FERC ¶ 61,013, at PP 34, 36 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at PP 221-24, *reh'g denied in pertinent part*, 109 FERC ¶ 61,157, at PP 204-06 (2004); *New Eng.*

IV. CHALLENGES TO PJM'S IMPACT SIMULATION MISS THE POINT OF THE SIMULATIONS AND, IN ANY EVENT, RELY ON AN INCORRECT ANALYSIS.

In the March 29 Filing, PJM estimated that, based on a market simulation of calendar year 2018, its proposed reserve market changes would have increased energy and reserve market billings by approximately $556 million.[195] Mr. Keech explained that PJM was updating and revising simulations PJM had developed and shared during the stakeholder process, by removing the impacts of re-solving the full unit commitment, and thereby focusing solely on the energy and reserve billing impacts of the market rule changes proposed here.[196] Mr. Keech also stressed that "there will be offsetting savings that are not quantified here."[197] Those savings include "anticipated reductions in the capacity market costs due to an increase in energy and reserve market revenues" as well as "additional [consumer] benefits due to stronger incentives"[198] for resource attributes that are more responsive to energy and reserve prices, i.e., "availability during all hours, flexibility, and a low incremental cost of production."[199]

PJM's cost impact estimate therefore was explicitly not a cost/benefit analysis, but was instead provided to update prior publicly released cost impact analyses. Viewed solely in those terms, PJM's simulations suggested the proposed rule changes could increase energy and reserve costs—*before* considering any offsetting benefits—by about

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Power Pool, 100 FERC ¶ 61,287, at P 71 (2002); *Cent. Hudson Gas & Elec. Corp.*, 86 FERC ¶ 61,062, at 61,223-24, *order on reh'g*, 88 FERC ¶ 61,138 (1999).

[195] March 29 Filing at 114-15; Keech Initial Aff. ¶¶ 28-46.

[196] Keech Initial Aff. ¶ 45.

[197] *Id.* ¶ 46.

[198] *Id.*

[199] *Id.*

two percent.[200] Putting this in context, the Commission is not required to "engage in painstaking cost-benefit analysis" when setting rates,[201] and "does not have to find net savings."[202] The Commission can "consider non-cost factors;"[203] and may permissibly find "that, on balance, increased system reliability justifie[s] even a net increase in costs."[204]

Exelon's affiant Mr. Schnitzer noted the limited focus of PJM's "incremental load payments" estimate, and supplemented PJM's showing with his own estimate of "the total market surplus gains, associated with PJM's proposal."[205] Mr. Schnitzer concluded that PJM's proposed rule changes would "create[ ] net benefits by procuring additional reserves above the status quo which offer increased reliability benefits and by reducing production costs through the reduction of costly load biasing and out-of-market actions."[206] Moreover, his quantification of these benefits is an "initial[] 'year one' estimate of the net benefits of PJM's proposal."[207] Mr. Schnitzer shows why "the net benefits of PJM's proposal will likely increase substantially over time."[208] As he explains, "more accurate price signals for operating reserves and energy achieved by implementing the new proposed ORDCs . . . will call forth and reveal new investment

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[200] Two percent is the increase of $556 million relative to the estimated 2018 energy and reserve market revenues under the status quo rules of approximately $26.8 billion. *See* Keech Initial Aff. at Table 3.

[201] *Process Gas Consumers Grp. v. FERC*, 866 F.2d 470, 477 (D.C. Cir. 1989).

[202] *AEMA* at 662.

[203] *Pub. Utils. Comm'n of Cal. v. FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004) (citing *Permian Basin Area Rate Cases*, 390 U.S. 747, 791 (1968)).

[204] *AEMA* at 662 (citing *Consol. Edison Co. of N.Y., Inc. v. FERC*, 510 F.3d 333, 342 (D.C. Cir. 2007)).

[205] Schnitzer Aff. ¶ 38.

[206] *Id.* ¶ 50.

[207] *Id.* ¶ 51.

[208] *Id.*

opportunities in resources and technologies able to provide flexible reserves and/or energy" which "will further lower production costs and facilitate the purchase of additional cost-effective reserves."[209] In addition, with a reasonably expected "significant increase in the amount of intermittent resources on the system in coming years," that will "increase the amount of additional reserves PJM must purchase above the MRR," PJM's ORDC methodology to regularly recalibrate the curve shape to reflect the latest estimates of uncertainty "will automatically adapt to these [intermittent resource] changes in an efficient manner by procuring the needed additional reserves through the market . . . and thus widen the net benefit gap between the status quo and PJM's proposal."[210]

While PJM does not adopt or endorse all of Mr. Schnitzer's particular estimates and assumptions, the benefits he identifies are real and substantial; they will offset the estimated initial costs of implementing PJM's proposal; and they can be reasonably expected to increase the value of PJM's proposal over time. The Commission has ample experience that shifting electric services and products from out-of-market procurement to competitive market pricing tends to increase market surplus and reduce over time the cost of that product or service to consumers. The Commission reasonably can expect the same long-term result here from allowing the reserve market to value and price reserves procured beyond the MRR.

The Commission should bear this larger context in mind as it evaluates criticisms, such as those from the IMM, of PJM's incremental energy and reserve market billing

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[209] *Id.* ¶ 51(a).

[210] *Id.* ¶ 51(b).

analysis. The IMM argues that such increase is on the order of $1.7 billion,[211] or about 6% of total energy and reserve market billings. The difference between the IMM's estimate and PJM's estimate largely revolves around the basis of comparison. PJM's incremental cost-impact estimates include an intermediate step intended to factor out impacts resulting from re-solving for a full unit commitment; the IMM treats that impact as if it were part of PJM's proposed rule changes. In his Reply Affidavit, Mr. Keech details the multiple reasons why the IMM's attribution of those cost impacts to PJM's proposal is inaccurate and unreasonable. Simply put, the IMM utilizes an inappropriate base case that would require PJM to produce a Day-ahead commitment that is exactly optimal for real-time operating conditions and includes additional variables that pollute the results.[212]

V. RELATIONSHIP TO CAPACITY MARKET

A. PJM Acknowledges that the Proposed Reforms May, over Time, Reduce Reliance on the Capacity Market, but that Relationship Does Not Require the Need for Reform to the Capacity Market at This Time.

PJM agrees with the arguments submitted by the R Street Institute and the Union of Concerned Scientists that continued enhancements to the energy and reserve market could result in less reliance on the capacity market for revenue sufficiency.[213] To the extent that these energy and reserve market reforms produce prices that are consistent with supply and demand fundamentals and better reflect the marginal costs of energy and reserves, the reduced reliance on the capacity market moves in the right direction. The energy and reserve markets provide a much different set of incentives than the capacity

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[211] IMM Protest at 58.

[212] Keech Reply Aff. ¶¶ 6-7.

[213] Comments of the R Street Institute, Docket Nos. EL19-58-000, et al., at 4-5 (May 14, 2019); Comments of the Union of Concerned Scientists, Docket Nos. EL19-58-000, et al., at 7-8 (May 14, 2019).

market for attributes such as low marginal operating costs, ramping capability and quick-start capability, etc., that are needed for operational reliability but do not manifest in the capacity market. Strengthening energy and reserve market incentives will send clearer investment signals for these characteristics and lessen the need for the capacity market to incentivize a less-defined set of resources.

While PJM anticipates that its proposal will increase energy and reserve market revenues by some amount, that does not necessitate major design changes to the capacity market in this docket. The capacity market has been modeled as a three-year forward auction in PJM since 2007. Since that time there have been many energy and reserve market changes made, including the implementation of shortage pricing in PJM in 2012. None of these energy and reserve market changes prompted a wholesale review of the capacity market, a restructuring of the VRR curve in the capacity market, or a change to the EAS offset. Indeed, the Commission expressly rejected in the PJM shortage pricing proceeding requests to change the EAS methodology to reflect possibly higher energy prices.[214] In the case of the instant proposal, no evidence has been provided that changes to the capacity market are needed. The capacity market has a defined timeline on which some of its key parameters including the CONE, the shape of the VRR curve, and the methodology used to determine the EAS Revenue Offset are reviewed. One such review was just completed in 2019.

It bears noting that the changes PJM proposes in this proceeding do not have a material effect on the capacity market. As PJM has shown, the impact of its proposal to energy and reserve market revenues is on the order of $556 million per year. The energy

[214] *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61, 057, at P 226 (2012).

and reserve markets settle over $25 billion per year. This is about a two percent change in the total revenues in the energy and ancillary service markets. Such a *de minimis* change in revenues should not prompt drastic action in the capacity market, especially when there is already an existing EAS Offset mechanism intended to offset energy and reserve market revenues from the capacity market.

The IMM also argues that the PJM Proposal necessitates changes in the shape of the VRR curve. They contend that the “higher of” 1.5 * Net CONE or Gross CONE used to compute point A on the VRR curve should be removed in favor of only using 1.5 * Net CONE. Their argument is based on the belief that if EAS revenues are sufficiently high such that the Net CONE is less than or equal to zero, that the VRR curve should be flat at $0/MW-day indicating that there is no need for additional capacity. The IMM fails to recognize that such EAS revenues could be very high at a time where PJM is not meeting the target reserve margin set by the Installed Reserve Margin. If this is the case, PJM’s markets should send a signal to attract new capacity even if the EAS revenues are high. This enhancement was added to the VRR curve in 2011 in during the Triennial Review that was done at that time. Removing it would unwind the very issue it was intended to fix. Additionally, no set of simulations on the record provide any indication that EAS revenues from the PJM Proposal will reach such high levels that the Net CONE could possibly reach zero.

The aforementioned argument regarding the VRR curve could be triggered today if there were a year with a significant amount of shortage pricing events, however, the IMM failed to even raise this as an issue during the Quadrennial Review. That initiative is the proper time to address concerns such as this, not this proceeding.

B. A Transition Mechanism Is Not Necessary To Find PJM's Proposal Is Just And Reasonable; However Should The Commission Require A Transition, It Should Be Narrowly Tailored.

Several parties advocate for changes to PJM's EAS Revenue Offset rules, such that any energy market revenue increases from the reserve market changes proposed in this proceeding will reduce capacity prices more quickly, without waiting for any corresponding revenue increases to be partially or fully reflected in the three-year historic data used for the EAS Revenue Offset, as would be the case under the currently effective Commission-approved Tariff provisions.

As PJM did not propose any changes to its EAS Revenue Offset in the FPA section 205 portion of its initial filing, arguments regarding the merits of any hypothetical changes that were not proposed are beyond the scope of this proceeding. Beyond this, the Commission retains its ability to act in this proceeding under either FPA sections 205 or 206, without requiring any changes to the EAS Revenue Offset. For example, the question of whether PJM's proposed reserve market changes made in one proceeding will cause Tariff provisions in other PJM markets to become unjust and unreasonable is a separate, distinct issue from the reserve market changes currently before the Commission. To this point, the United States Court of Appeals for the District of Columbia Circuit in *AEMA* found that the fact that a filing may make other provisions unjust and unreasonable does not make that filing unjust and unreasonable.[215] Indeed, the Commission has seen no problem with such sequencing in the past, addressing in subsequent proceedings claims that tariff provisions had become unjust and unreasonable

[215] *Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 664 (D.C. Cir. 2017) ("*AEMA*").

as the result of other tariff changes accepted in separate, prior proceedings.[216] Here, parties have not demonstrated with substantial evidence that the reserve market changes proposed by PJM will render the current EAS Revenue Offset provisions for the capacity market unjust and unreasonable. Nor could they make that showing, as future EAS impacts are speculative at this time.

Further, there are many examples of PJM tariff change filings that could significantly impact pricing in either the energy or ancillary services markets, that did result in any Commission directive to PJM to modify the EAS Revenue Offset.[217]

While the issue of changes to the EAS Revenue Offset for determining capacity market prices is beyond the scope of this proceeding, PJM will nonetheless address some of the concerns raised by commenters. As PJM stated in the March 29 Filing, Capacity Resources are typically long-term assets, and the EAS Revenue Offset calculated and used in the capacity auction for any given Delivery Year does not, and was never intended to, precisely match the actual revenues received by a given resource in the energy and ancillary service markets in the Delivery Year. As PJM noted, this approach was "consciously chosen" with the knowledge that any predictions of actual future year EAS revenues will likely be incorrect, and therefore using actual historic revenues received is a more rational solution, given the fundamental timing mismatch between the years when actual EAS revenues are received and when future capacity revenues are realized.

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[216] *See, e.g.*, *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,091, at P 30 (2014) (finding pre-existing market price adders have been rendered unjust and unreasonable due to evolving market mechanisms, including PJM's implementation of its Capacity Market auctions.").

[217] *See e.g.*, *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,058 (2019) (requiring changes to fast-start pricing); *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER17-1590-000 (July 7, 2017) (approving changes to transient shortage pricing); *PJM Interconnection, L.L.C., et al.*, 162 FERC ¶ 61,150 (2018) (requiring changes to implement five-minute settlement intervals).

Commenters overlook numerous factors in calling for changes to PJM's current rules regarding the EAS Revenue Offset.

- Adopting a transitional change in the EAS Revenue Offsets based on simulated energy market price forecasts could very likely result in Capacity Market Sellers trading known future capacity revenues based on speculation as to the possibility of future increased energy and reserve market revenues. This would be contrary to the design of the EAS Revenue Offset and the mechanism by which it was intended to work, as described above.

- The EAS Revenue Offset only affects Net CONE, which is one of many assumptions embedded in the VRR curve that is used to clear the capacity auctions. Most capacity market clearing price changes will be due to Capacity Market Seller changes in offer behavior—based on choices by those sellers rather than administrative auction assumption changes by PJM. Guessing how capacity market sellers will change their offers will be not much more than that—guesses.

- The magnitude of the estimated impact on future energy market revenues from reserve pricing changes is likely to be well within the margin of error for any such estimate. But forecasts of future energy prices, even with sophisticated simulations, are inherently uncertain, and could be off by a substantial margin. Changing market rules now in an attempt to predict the course of a market transition that will play out over the course of only a few annual capacity auctions assumes more precision in forecasting than is warranted.

- Imposing a short-term change on the EAS Revenue Offset based on perceptions of the impact of other market rule changes would set a poor precedent. Ad hoc changes focused in each case on a particular energy market rule change would simply increase inconsistency in EAS Revenue Offset estimates over time. That would undercut the market value of having a straightforward, consistent methodology that sellers have learned to integrate into their Capacity Sell Offers. By the same token, the proponents of a one-time change to the present design of the EAS Revenue Offset do not set forth an appropriate 'limiting principle' so that the Commission is not faced with repeated requests for one-off re-openers to the EAS Revenue Offset for any particular market design change. Absent such a clear limiting principle, re-opening this matter on an 'ad hoc' process could place the Commission and all parties on a 'slippery slope' that only adds volatility to the capacity market with results sometimes benefitting customers and sometimes working against their interests.

- Mr. Keech noted in his Initial Affidavit included in the March 29 Filing that "[w]hen compared to the benchmark of Case B, the impacts of the PJM proposal are modest. The Load Weighted Average LMP increases $0.46/MWh and load payments for energy increase by approximately $366 million. These represent increases of 1.23% and 1.31%, respectively."[218] Accordingly, even if PJM did propose a transition mechanism in its initial filing the small change in the average LMP will make no difference in the VRR curve, as this change is well within the range of error in historical EAS Revenue Offset.[219]

However, if the Commission nonetheless finds it necessary to require some kind of transition mechanism with respect to the EAS Revenue Offset, PJM would encourage the Commission to keep two considerations in mind. First, the transition mechanism should not seek to reopen BRAs that have already run, and should not seek to take back revenues already allocated pursuant to those BRAs. Business decisions by market participants have already been made with respect to these BRAs, and it would be inequitable to impose retroactive changes on the information that those decisions were predicated on. Second, any transition mechanism for subsequent Delivery Years where a BRA has not yet been conducted should be limited in scope and narrowly address the concern about how long it will take for the capacity market to catch up with the changes in expected energy and ancillary service revenues or the potential disruption or volatility of such impact. One possible approach for changes to the EAS Revenue Offset would be to weight the most recent year more heavily, which would have the effect of updating the EAS Revenue Offset more quickly. This would be a more measured approach than what has been proposed by some commenters in this proceeding, while still achieving a more accelerated timeline than the current mechanism under PJM's Tariff.

[218] Keech Initial Aff. ¶ 44.

[219] Keech Reply Aff. ¶ 15.

VI. OTHER ISSUES

A. While PJM Is Open To Allowing Greater Demand Response Participation In Reserve Markets, Demand Response Resources Must Be Registered As Economic To Participate.

A couple commenters raised issues with regard to how demand resources will be able to participate in the restructured reserve markets. First, CEA and the IMM argue that there should be no limit on the amount of demand response resources that can provide reserves.[220] As explained in the March 29 Filing, PJM proposes to maintain a limit on the amount of demand response resources that can be counted toward meeting the Minimum Synchronized Reserve Requirement and Minimum 30-minute Reserve Requirement.[221] PJM explained that the caps were initially adopted "to ensure demand response was as effective as other resources to manage the grid based on short-term issues," and that the PJM Operating Committee periodically reviews whether an increase in the cap is warranted.[222] However, upon review of the comments raised, PJM acknowledges that it would be just and reasonable for the Commission, in the context of a comprehensive order addressing the reserve pricing issues raised by PJM in this proceeding to lift these caps and allow demand response resources to compete to provide reserves without limit. Because demand response resources historically have never come close to approaching even the existing reserve participation limits, PJM does not at this time see a present reliability reason to maintain the caps.

Second, CEA argues that the capacity only demand response resources registered as Emergency Load Response and Pre-emergency Load Response should be allowed to

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[220] CEA Protest at 17-19, 25-26.

[221] *See* March 29 Filing at 96-97.

[222] *See* March 29 Filing at 97.

provide Secondary Reserves, to the extent the resource has a 30-minute notification time.[223] The Commission should reject this proposal. Under the Tariff and the Reliability Assurance Agreement, such demand response resources are only "available for dispatch during PJM-declared pre-emergency events and emergency events."[224] Pre-emergency and emergency events may only be called upon specific circumstances, and PJM does not intend to alter those triggers here.[225] Thus, such resources are treated comparably to Maximum Emergency generation, as such generating units or parts of generating units also are not eligible to provide reserves under the current or proposed rules.[226]

Given the limitation on when these Maximum Emergency generation, Emergency Load Response and Pre-emergency Load Response resources are required to respond, it would not be good utility practice to rely on them to maintain reserves on the system outside of the pre-emergency and emergency events for which they committed. Of course, to the extent the load response resource seller desires to participate in the energy and ancillary services markets, the seller may register the resource as an Economic Load Response Participant, under both the current and proposed market rules.[227] Sellers of 30-

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[223] CEA Protest at 20-25.

[224] Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region, Schedule 6, section A.6; Tariff, Attachment DD-1, section A.6.

[225] *See, e.g.*, Operating Agreement, Schedule 1, section 8 (setting forth the rules for Emergency Load Response and Pre-emergency Load Response programs).

[226] Operating Agreement, Schedule 1, section 1.7.19A(a) ("Synchronized Reserve can be supplied from non-emergency generation resources and/or Demand Resources located within the metered boundaries of the PJM Region."); Operating Agreement, Schedule 1, section 1.7.19A.01(a) ("Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. Resources, the entire output of which has been designated as emergency energy, and resources that aren't available to provide energy, are not eligible to provide Non-Synchronized Reserve.").

[227] *See* Operating Agreement, Schedule 1, section 1.5A.3.

minute demand response resources currently registered only in the Pre-emergency and emergency Load Response programs may find that a secondary reserve market is economic and register their resources to participate.

B. PJM Has Proposed Appropriate Lost Opportunity Cost Rules to Ensure Resources Are Indifferent to Proving Energy Or Reserves.

To ensure that resources are financially indifferent to providing reserves or energy, PJM's market rules provide resources lost opportunity cost credits for any profits foregone by following PJM's dispatch instruction rather than providing energy and taking LMP. PJM expanded these rules in the March 29 Filing to account for the alignment of the day-ahead and real-time markets and procurement of all three reserve products in both markets. The IMM challenges PJM's proposed rules, arguing that "PJM does not justify why it should pay [lost opportunity costs] amount when it is a loss to the resource"[228]

To the contrary, PJM's proposed rules ensure that resources are indifferent to providing energy or reserve, and to following PJM dispatch instructions, generally. In general, PJM's proposed overall lost opportunity cost credit calculations for the three reserve markets are similar to those calculations in PJM's current energy market, where resources are compensated for lost opportunity costs incurred as a result of following PJM dispatch (e.g., a generator backing down to provide less energy). The lost opportunity cost credit for each reserve market needs to account for all applicable costs and credits. The implementation of consistent reserve markets in both day-ahead and real-time results in day-ahead and Balancing Opportunity costs and day-ahead and Balancing Market Clearing Price credits. In addition, the difference in commitments for

[228] IMM Protest at 57.

energy and reserves between the day-ahead and real-time markets introduces the need for a new component in the overall lost opportunity cost credit calculation: the Market Revenue Neutrality Offset. This component represents revenue above cost (i.e., profit) that offsets losses across the energy and reserve markets due to a change in megawatt assignments for a resource between the day-ahead and real-time energy or reserve markets as a result of following PJM operator instructions. Consequently, the Market Revenue Neutrality Offset needs to be accounted for in the overall lost opportunity cost credit calculation to ensure that a resource is properly compensated for providing energy and reserves. Without these rules assuring compensation for foregone profits, resources would not have sufficient financial incentive to follow PJM dispatch for energy and reserve assignments.

VII. CONCLUSION

For the reasons set forth herein and in the March 29 Filing, the Commission should find that PJM's current reserve market rules are unjust and unreasonable, and that PJM's proposal constitutes a just and reasonable replacement for the current reserve market design.

Respectfully submitted,

/s/ *Paul M. Flynn*

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June 21, 2019

Attachment A

Reply Affidavit of Drs. William W. Hogan and Susan L. Pope on Behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER19-1486-000**
	)	
PJM Interconnection, L.L.C.	)	**Docket No. EL19-58-000**

REPLY AFFIDAVIT OF
DRS. WILLIAM W. HOGAN AND SUSAN L. POPE
ON BEHALF OF PJM INTERCONNECTION, L.L.C

1. Our names are Dr. William W. Hogan and Dr. Susan L. Pope. Dr. Hogan is a Professor at the John F. Kennedy School of Government, Harvard University, and is a Senior Consultant for FTI Consulting, Inc.; Dr. Pope is employed by FTI Consulting, Inc. as a Managing Director. We are submitting this reply affidavit on behalf of PJM Interconnection, L.L.C. ("PJM") to support its reserve market reforms in this proceeding. Our qualifications were provided as Exhibits 2 and 3 to our initial affidavit in this proceeding.

2. As described in our initial affidavit in this proceeding, PJM engaged FTI Consulting, acting through us, to advise PJM on the comprehensive reform of the PJM reserve markets, including, specifically, development of an improved Operating Reserve Demand Curve ("ORDC"). Pursuant to our engagement, we addressed the structure of the ORDC, the maximum $/MWh Reserve Penalty Factor, other inputs into the ORDC, energy and reserve co-optimization, reserve and energy market price formation, locational application of the ORDC and reserve markets, day-ahead and real-time application of an ORDC, and connections with market power mitigation. The results of this review and our findings are contained in the report, entitled "PJM Reserve Markets: Operating Reserve Demand Curve Enhancements" ("PJM ORDC Report"). The PJM ORDC Report was provided as Exhibit 1 to our initial affidavit which supported PJM's March 29, 2019 filing in this proceeding.

3. In this reply affidavit, we respond to various commenters challenges to PJM's March 29, 2019 filing through the attached report entitled "PJM Reserve Markets: Operating Reserve Demand Curve – Reply Comments" ("Hogan & Pope Reply"), which is provided as Exhibit 1 to this reply affidavit. In this affidavit, we affirm and adopt, as if set forth in this affidavit, the analysis and all findings and conclusions contained in the Hogan & Pope Reply to provide support for PJM's proposal to reform its ORDC.

4. In the Hogan & Pope Reply, we affirm our initial assessment that the existing operating reserve markets in PJM can and should be replaced by an enhanced design that better meets the standard of just and reasonable rates and that PJM's

proposed terms for developing, applying and updating ORDCs would address these shortcomings. The PJM proposal for enhancement of operating reserve products and prices is a significant advance in the market design and will contribute to just and reasonable rates consistent with economic efficiency, reliability, open access and non-discrimination.

5. This concludes our affidavit.

Attachment A
Exhibit 1

PJM Reserve Markets:
Operating Reserve Demand Curve Enhancements -
Reply Comments

PJM Reserve Markets: Operating Reserve Demand Curve Enhancements - Reply Comments

William W. Hogan[i], Harvard University
Susan L. Pope, FTI Consulting, Inc.

June 14, 2019

Overview

Comments on the PJM filing for "Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C." (PJM Interconnection, 2019) addressed many different elements in the proposal, including the Hogan-Pope report (Attachment C of the PJM filing). Many comments on the PJM proposal and our report were supportive of the proposed operating reserve demand curve reforms and enhancements. Some of the comments raise new issues or suggest improvements in price formation reforms. A few raised objections to certain component details in the proposal. Many of these detailed objections make implicit or explicit assumptions that are inconsistent with the principles underlying the analysis in our report as well as the elements of the PJM filing deriving from this analysis. To address these objections, the first section of this reply emphasizes broad themes that are either missing from consideration in the detailed objections or need restatement to support understanding of the purpose and design of the PJM enhancements. In the second section we address several of the proposed refinements to PJM's proposal.

Market Design Elements

PJM's proposed enhancements to price formation fit within the context of the larger real-time and day-ahead PJM market design. An objective of the proposed reforms and enhancements is to correct material deficiencies in PJM's existing models for procurement and pricing of operating reserves. PJM proposes a new model that will yield operating reserve clearing prices and quantities that better approximate efficient market outcomes in keeping with the principles of open access and non-discrimination. Improvement in the efficiency of market outcomes means, importantly, better incentives for load participation, better incentives for supply availability when and where it is most needed, and a better balance between supply and demand without the need for out-of-market interventions. In addition, enhancement to price formation for operating reserves will simplify market power monitoring and mitigation. Improvements to operating reserve price formation will result in coinciding improvements to price formation in other markets, such as energy, which are inter-related within the overall PJM market design.

The need for and role of an operating reserve demand curve reform in PJM is separate from the design and operation of the capacity market, as explained below. The proposed operating reserve demand curve reform does not perform a function redundant to the capacity market. The economic efficiencies introduced through the basic operating reserve demand curve structure proposed in the reform would arise in an overall electricity market design with or without a capacity market and, as such, the structure is not subordinate to the capacity market design. Specifically, the proposed operating reserve demand curve reforms represent the day-ahead or real-time value of reserves in excess of the minimum reliability requirements better than PJM's current operating reserve model. This value is included in clearing prices for energy, providing a consistent and hedgeable wholesale energy price signal to all supply and load that includes the approximated marginal value of supply in avoiding a possible loss of load.[1] The proposed operating reserve demand curve follows from the basic principles of efficient real-time dispatch to maximize net benefits, rather than from assumptions that would reduce short-run clearing prices to reduce short run load payments, thereby sacrificing efficiency and shifting costs and revenues among markets and market participants.

Open Access and Non-Discrimination

The foundations for efficient markets in electricity rest on the principles of open access and non-discrimination. These principles have been consistently maintained at least since Order 888 (FERC, 1996). One design foundation is the reliance on efficient markets with clearing prices and payments that support the welfare maximizing solution. This means, importantly, that the market-clearing prices and payments should be the same for all similarly situated participants providing the same service at a place and time. For example, renewable energy generators, which face no variable costs when supply is available, should be paid the same price for their energy production as other generators in the same location that incur positive variable costs to produce energy. This same market design fundamental should apply to operating reserves. As PJM has shown in its filing, the existing design, which discriminates between Tier 1 and Tier 2 operating reserves, does not meet this test. Part of the reform of operating reserve pricing and payments should be to meet the efficient market requirement that capacity which provides the same reserve services should be paid the same price. Justifications of the status quo that use underlying opportunity cost arguments to discriminate in payments for reserves do not meet the basic test of non-discrimination any more than would paying nothing for renewable energy generation.[2]

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1 For example, "Figure 4 [showing] how an efficient market price is determined where supply and demand curves intersect" assumes the cost of supply determining an "efficient price" should exclude its short-run value in avoiding a possible loss of load. Protest of the Independent Market Monitor for PJM, (IMM, May 15), 2019, p. 24.

2 For example: "Tier 1 has no opportunity costs associated with providing reserves – in fact, the call to provide reserves would increase their earnings – while Tier 2 actually loses money by responding. This justifies the discrepancy in the payments each receives." Protest of the PJM Load/Customer Coalition. (Load Coalition) May 15, 2019, p.22.

Market Design and Reliability Constraints

Electricity markets operate under a stringent system of reliability rules. These rules have developed over many years of experience and analysis in order to safely and reliably operate complex interconnected transmission grids on which the energy flows adjust more quickly than human or even computer response. For example, the speed of response of the physical system is much faster than control systems that govern the dispatch. In the event of a major contingency, the first few milliseconds or seconds can cause dynamic adjustments that destabilize the grid and create a cascading blackout. In order to protect against such events, the dispatch is limited by so-called N-1 contingency constraints to ensure that in the event of the loss of a line or a major generator (either of which is a “single”, -1, contingency) the overall system will remain naturally stable after the contingency occurs for long enough to allow system control adjustments.

The purpose of efficient market design is not to replace or change these reliability rules. Rather, the market design requirement is to account for these constraints and determine market-clearing prices that reflect the constraints and operator practices. These reliability rules motivate the long-term resource adequacy standard governing the capacity market as well as the separate reliability rules for operating the real-time dispatch. To achieve the latter within a regimen of open access and non-discrimination requires the price formation, occurring within a real-time market design, to provide incentives to supply and dispatchable load to follow the dispatch and maintain reliability.

Capacity Markets and Operating Reserve Demand Curves

The PJM reserve pricing proposal is not redundant to the capacity market, although, like the capacity market, its development was originally motivated by what has been referred to as the “missing money” problem. Unlike the capacity market, the purpose of PJM’s reserve pricing proposal is to get the prices right in the reserve and energy markets by ensuring that those prices are consistent with and reflective of the value of the services resources are providing. The fact that reserve and energy prices, and therefore energy and ancillary service revenues, will be higher under PJM’s proposal would likely lead to a reduction in capacity market prices and therefore capacity market revenues. However, that is a corollary effect of the PJM proposal, and not its objective.

The long-term resource adequacy rules focus on system planning requirements and installed capacity. These necessarily look many years ahead and are based on planning models that are quite distinct from the models used to insure reliable real-time operation of the system. Modeling studies of the typical one-day-in-ten-years type reliability standard lead to requirements for aggregate capacity to meet peak system load over a long-term planning horizon. These studies provide the foundations for the demand and supply representations in forward capacity auctions.

By contrast, real-time operating rules and reliability requirements, including those for operating reserves, have the purpose of insuring reliability under the short-run conditions of the day-ahead commitment and real-time dispatch intervals. Plant outages, unscheduled maintenance, intermittent supply, surprising load conditions and a host of other related situations create reliability challenges. The real-time reliability rules manage these short-run uncertainties to keep the lights on over periods of seconds and hours; these short-run uncertainties are fundamentally different than the longer-term uncertainties analyzed in multiple scenarios run over months and years for planning studies. The purpose of operating reserves is to address the short-term uncertainties and maintain secure operations within the time-step of the real-time dispatch.

The installed reserves in the planning context and operating reserves in the real-time dispatch are separate constructs. The basic operating requirements take as given the installed capacity configuration, which for the case of PJM flow from the capacity market. Hence, efficient design of the operating reserve demand curve, to support efficient and reliable real-time operation, is not affected by the capacity market. The main connection would be that reforms to the operating reserve demand curve will affect anticipated energy and operating reserve prices and revenues from future operations, which should affect the results of the capacity market. Contrary to some of the comments,[3] the efficiency principles that drive the design of the operating reserve demand curve should not be modified in the presence or absence of a planning capacity market.

Confusion about the distinct purpose of the proposed operating reserve demand curve versus the capacity market, appears in the implicit argument in some comments on the PJM proposal. The commenters' assumption is that the purpose of the proposed operating reserve demand curve reform is to address the missing money that gives rise to the capacity market. From this perspective, the reforms proposed with the operating reserve demand curve appear redundant and unnecessary, since the missing money issues is intended to be addressed by the capacity market in PJM. This implicit argument fundamentally mischaracterizes the purpose of the proposed operating reserve curve reform. The proposed PJM reform addresses the problem of inadequate scarcity pricing in real-time, thereby providing the wrong dispatch incentives in real-time, for both load and generation and for both operating reserves and energy. The absence of scarcity prices means that the prices are too low and real-time reliability is not being reinforced by pricing. The missing money problem is a consequence, in large part, of inefficient and discriminatory pricing in real time; hence inadequate scarcity pricing is part of this story. Therefore, fixing scarcity pricing in real time will affect the missing money estimates, but that is not the purpose of the operating reserve pricing reform. The need for an efficient operating reserve demand curve in real-time is independent of the existence of a capacity market, even if the capacity market completely solved the missing money problem. Although physical scarcity is always a problem, better pricing in scarce situations is a good thing.

3 "PJM already has a capacity market to provide capacity scarcity rents. PJM's energy market does not require the pervasive scarcity pricing inherent in an extended downward sloping ORDC to produce efficient market outcomes or just and reasonable rates." (IMM, May 15), p. 8.

Minimum Reserve Requirements and Operating Reserve Demand Curves

Like other RTOs, PJM applies a reserve penalty factor when reserves fall below the Minimum Reserve Requirement (MRR). The innovation with the proposed operating reserve demand curve is recognition of the value of reserve levels above the MRR arising from the probability that, even at these levels, PJM could run short of reserves in real-time.

PJM's N-1 reliability requirements constrain the feasible real-time economic dispatch. These requirements include minimum levels of operating reserves that must be set just before the start of each dispatch interval. If a type of reserves were to fall below its MRR, the system operator would invoke various emergency actions in order to restore the reserve level for the start of the next dispatch interval. When initial reserves are at or below the MRR, the value of incremental operating reserves is the cost of the marginal emergency action. This cost would be incurred before the dispatch period as part of the emergency action to ensure compliance with the MRR.

The costs of emergency actions are varied. In order to represent these costs, PJM's proposed operating reserve curve model applies a penalty factor of $2000/MWh, which is a simple proxy for a range of emergency actions undertaken when additional market-driven reserves are not available.

An innovation of the Operating Reserve Demand Curve (ORDC), as in PJM's proposal, occurs when available reserves are above the MRR. These operating reserves are recognized as having a value greater than zero. With the reformed ORDC reserves above the MRR have value to the extent that they reduce the probability of a reserve shortage in future intervals. Like the penalty value representing costs incurred when reserves are less than the MRR, this is an estimate of the willingness to pay for additional reserves at the time of the dispatch. Comments that imply that reserves should not have a price above zero when reserve levels are above the MRR cannot be correct, on their face.[4] It is clear that reliability would be improved with more operating reserves, which would lower the chance of falling below the MRR during the dispatch interval. A price of zero cannot be the right answer.

Recognizing this, the challenge is to define a methodology for determining the marginal value of operating reserves in excess of the MRR. This is done as part of the PJM proposal. The proposed operating reserve demand curve defines the price in expected value terms, i.e., the value of a given level of operating reserves is the expected value of its avoiding a future reserve shortage. Actual violations of the MRR are identified ex ante, and operationally addressed in the dispatch period. But even if the MRR is not violated there is continuing uncertainty about the availability of sufficient reserves over future dispatch intervals. If there is a call on the operating reserves sometime in the relevant interval, and the reserve level then falls below the MRR constraint, the system operator will have to invoke emergency actions and the system will see the costs of the

[4] For example, "PJM's reserve markets do not produce prices equal to zero unless the quantity of zero cost reserves exceeds the reserve requirement." IMM, May 15, p. 13.

penalty factor. The probability of this event, multiplied by the penalty factor, defines the implied value of scheduling a marginal unit of operating reserves above the MRR. The additional reserves enable the system to avoid the costs of emergency actions with some probability greater than zero, even when the MRR constraint is not violated in the dispatch.

Calculating and plotting the expected value of each level of reserves above the MRR produces a downward sloping demand curve as shown in the illustrative PJM calculations. In principle, this demand curve extends without limit, although the implied operating reserve price declines to be very close to zero. This operating reserve demand curve combines in a natural way with the existing deterministic dispatch model used in the day-ahead and real-time markets, and allows for co-optimization of energy and reserves in the dispatch, so that both energy and reserve clearing prices and quantities account for the value of incremental reserves in avoiding costs of emergency actions that might, with some probability, be needed to maintain reliability.

Hence, unlike the assumption of some of the comments that there should be no fixed price below the MRR,[5] there is a principled basis for PJM's construction of an operating reserve demand curve is comprised of the fixed price over the range from zero to the MRR, and a declining price over increasing levels of reserves above the minimum level. The structure follows from the market design principle of forming prices to be as consistent as possible with the reliability constraints maintained by the system operator. If PJM's reliability constraints and rules were to change in the future, then so too would there be a change in the form of the operating reserve demand curve. But given the existing operating reserve reliability constraints, the PJM proposal provides a workable approximation of the implied operating reserve demand curves.

Scarcity and Shortage Pricing

The foregoing outline of the derivation of the operating reserve demand curve explains an apparent confusion in terms as discussed in the IMM comments, where there is a distinction made between shortage pricing and scarcity pricing.[6] The IMM proposed definitions of shortage pricing and scarcity pricing are consistent with the PJM proposal.[7] Under this distinction, shortage pricing applies when the available reserves fall below the MRR. The more inclusive term of scarcity pricing applies over the full range of operating reserve demand.

As discussed above in explaining the underlying principles used for the design of the operating reserve demand curve, scarcity pricing is the applicable concept, and shortage pricing is a subset of the full characterization. The referenced IMM comments simply assert that there is no need or justification for valuing reserves in excess of the MRR, i.e., in the absence of a shortage. But this

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5 See Affidavit of James F. Wilson in Support of The Protests of The Clean Energy Advocates and The PJM Load/Customer Coalition, May 15, 2019, p. 17-18.

6 IMM, May 15,p. 12.

7 IMM, May 15, fn, 15, p. 12.

is merely an assertion, motivated by a distinction in terminology, without any supporting argument or analysis.

It is clear that increased reserves improve reliability and reduce the chance of incurring shortage costs over the relevant dispatch horizon. Hence, it is clear that scarcity pricing should be included as part of the market design and operating reserve demand curve model. The scarcity price of reserves will interact with energy dispatch through co-optimization to determine consistent energy and reserve prices that support the efficient outcome. Given the energy and reserve dispatch solution, the marginal generator that can provide both energy and reserves will be indifferent to the choice and follow the system operator schedule, because the prices support the energy and reserve schedules with an adequate valuation of reserves. Without full scarcity pricing, and instead using just shortage pricing for reserve levels less than the MRR, the operating reserve model would not enable the efficient dispatch solution in which reserves in excess of MRR have value; the system operator would continue to invoke out-of-market actions to obtain additional reserves above the MRR. Scarcity pricing is not a problem, scarcity pricing is part of the solution. Shortage pricing alone (as defined herein) is insufficient.

Costs and Revenues

The goal of efficient market design is to support the welfare maximization of benefits minus costs in the short- and long-term provision of reliable electric supply. In the simple case of fixed demand (i.e., a system with no price-responsive load), this reduces to the familiar problem of solving a security-constrained least-cost economic dispatch. Locational market-clearing prices and payments associated with the efficient dispatch will support the efficient dispatch schedules.

Given the efficient, market-clearing prices, we can determine the payments by load and the revenues for generators. These payments are not the same thing as costs from the perspective of the system as a whole. The simple example of economic dispatch with fixed load would illustrate the point. For the least cost solution, the total cost of the system would be the sum of the individual generator costs for their dispatch schedules. The market clearing prices would be determined by the marginal conditions, for example with the price at a location equal to the variable cost of the last unit dispatched at the location, if it is running below capacity. The total revenue for the generators, and the payments by the load, would be the market-clearing prices times the quantities at each location.

This total load payment would depend on many things, but it would be at least as large as the total generator costs. The difference would be the contribution that could help pay back the investment in the generator and reduce compensation required from the capacity market.

This basic characterization of the efficient market solution reveals the problem in those comments that object that the PJM pricing reforms might increase total payments by load for energy.[8] The

[8] Protest of the PJM Load/Customer Coalition, May 15, p. 9.

purpose of efficient dispatch and pricing is to reduce the total system costs, not to increase or decrease the payments by load. To the extent there is an increase in payments by load under the reformed operating reserve demand curves, this would be a correction of the inefficiency hidden in the inefficient operating reserve demand curve treatment of the current system.

Demand Curve Cascade Models

The PJM proposal includes a form of cascade model that reflects the hierarchy of several types of reserves and is used to construct additive requirements for nested operating reserve zones within PJM. Some of the comments object that the proposed cascade model is not consistent with the underlying principles of the operating reserve demand curve as explained in the Hogan-Pope report.[9] As a technical matter, this is correct. However, as explained in the PJM proposal, the cascade model allows for a simpler implementation and more closely follows the current reliability practice embedded in system operations in PJM.

The relevant question is whether the cascade model provides a workable approximation of the value of operating reserves of different types and in different places given PJM's proposed implementation in its co-optimized dispatch. As explained in the Hogan-Pope report,[10] a numerical comparison of the prices at a level just above the MRR provides the anchor point for comparing the respective representations of the operating reserve demand curve. Commenters objected that the comparison was not done with actual PJM data.[11] It is true that the comparison was not performed for all possible actual probability distributions. However, the parameters used for the comparison were provided by PJM as representative of the actual distributions. For purposes of the numerical calibration, this is all that is required to demonstrate that the two approaches are similar, and that the PJM approach provides a workable approximation that will be easier to implement and maintain.

Demand Participation

The comments that object to the PJM proposal generally ignore the benefits of better incentives for demand participation. Implementation of the operating reserve demand curve and co-optimization to support both efficiency and consistent energy and reserve prices will translate into generally improved price signals for market participants. A virtuous circle should follow for loads that have the ability to be dispatched and who do not wish to pay the higher scarcity-induced prices during tight conditions. If load participates, overall efficiency will improve. This would be a major benefit that could be of increasing relevance in the future development of distributed energy resources that would look like load participation from the perspective of the wholesale market. Absent adequate scarcity pricing, demand and distributed energy resources would not see efficient energy or reserve prices.

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9 For example, see IMM, May 15, p. 32.

10 Hogan and Pope report with PJM filing, March 29, pp. 46-47.

11 IMM, May 15, p. 32.

Market Power Mitigation

A benefit similar to increased demand participation would be the compatibility of the operating reserve demand curve with existing practices for generator market power mitigation.[12] In particular, as explained in the PJM proposal, the operating reserve demand curve targets scarcity pricing. The scarcity prices from the demand curve do not depend on or arise from an exercise of generator withholding to exercise market power and thereby increase energy prices. Hence, the use of must-offer rules with offer caps for generators with market power can continue, with no ambiguity about the source of higher prices as arising from market power.

Prices increasing because of an exercise of generator market power would be accompanied with reduced economic efficiency, and would be a problem. But prices increasing due to scarcity conditions would be accompanied with increased efficiency, and would be a solution. The operating reserve demand curve makes this distinction clear and simplifies the otherwise complicated problem of mitigating market power.

Operating Reserve Demand Curve Refinements

Certain comments were directed at extensions of the PJM operating demand curve proposal. These included suggestions for an alternative operating reserve demand curve, providing a "Circuit Breaker" for scarcity pricing, alternative methods of estimating the probability distribution for the operating reserve demand curve, and the treatment of minimum generation conditions.

Alternative Demand Curve

In two related comments Wilson suggests an alternative operating reserve demand curve. The argument is developed in the Wilson Affidavit in support of Clean Energy Advocates nd then apparently illustrated in the graphic in the Affidavit in support of the Load/Customer Coalition.[13] The essence of these combined Wilson comments is to distinguish between the "Security Minimum" and the "Minimum Reserve Requirement (MRR)" in defining the operating reserve demand curve.

Wilson refers to the language in prior papers by Hogan and Pope that explains the first principles based on the "Security Minimum," which Wilson asserts must be less than the MRR. However, as explained in the Hogan and Pope report, the objective is to determine prices that reflect operator actions. In the PJM application, the MRR defines the level where the system operator would begin to take emergency actions ex ante to provide the level of reserves before the start of the dispatch interval.[14] Hence, the MRR is the appropriate reference point for setting the price equal to the

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[12] See Affidavit of A. Joseph Cavicchi on Behalf of the PJM Power Providers ("P3") Group, May 15, p.22.

[13] Affidavit of James F. Wilson in Support of The Protest of The Clean Energy Advocates ("Wilson Affidavit – ORDC"), May 15, pp. 10-15; Affidavit of James F. Wilson In Support of The Protests of The Clean Energy Advocates And The PJM Load/Customer Coalition ("Wilson Affidavit – Transition"), May 15, p. 18.

[14] See also, Affidavit of Dr. Patricio Rocha Garrido on behalf of PJM Interconnection, L.L.C. March 29, p. 12

costs of those emergency actions. This is the logical equivalent to the basic concepts in the Hogan and Pope prior discussion of "Security Minimum." The concepts are the same, and any distinction in this context is simply semantic.

In addition, Wilson asserts that the loss of load probability at the MRR must be very small, and uses an illustrative value of 0.001, or one tenth of one percent.[15] Although there is no derivation to support this illustrative assumption, it clearly is not illustrative. By construction, when just below the MRR the operator will take action with certainty, i.e. probability 1.0, or 100%. At slightly above the MRR, the relevant probability would be the chance of a net increase in load minus generation from the respective forecasts, implying a use of reserves. For a symmetric distribution, this probability should be close to 0.5 or 50% probability that over the coming dispatch horizon the reserves would fall below the MRR ex post.

Either way, the alternative operating reserve demand curve proposed by Wilson is not consistent with the basic argument as elaborated in the Hogan and Pope report. If PJM were to change the MRR to a lower amount, or change the operator actions, then the estimation of the operating reserve demand curve would change accordingly. But the semantic confusion does not point to a better operating reserve demand curve given PJM's actual practices.

Circuit Breaker

The normal expectation is that scarcity conditions would be episodic and not of long duration. In the rare event of a significant loss of capacity, the duration of scarcity conditions could be extended. This circumstance and the ability of everyone in the system to recognize and make material adjustments in load requirements would substantially alter the underlying assumptions in the formulation of the operating reserve demand curve. In other words, the scarcity prices that would be justified for relatively short duration would not be applicable for extended periods of operation. The suggestion is to develop a "circuit breaker" or "stop loss mechanism" to revise the formulation of scarcity pricing under these circumstances.[16]

Similar mechanisms exist in other markets, such as in Australia, where the circuit breaker puts a limit on high energy prices over an extended period of time. This is a backstop mechanism, but seldom has been triggered. Wilson reports a discussion of his Circuit Breaker proposal in the stakeholder process. This is a proposal that PJM could consider at a later time. Although developing such a backstop measure, to be invoked only under extreme circumstances, might be a supportive refinement of the PJM proposal, it should not be a principal concern at this stage.

[15] Wilson Clean Energy Affidavit, p. 12.

[16] Wilson Load Coalition Affidavit, pp. 14-17.

Reserve Change Probability Distributions

The report by Griffey[17] raises the question about the PJM proposed method for estimating the probability distribution for anticipated reserve changes over the appropriate interval. There are two issues here. One relates to the treatment of the components of the probability distributions and the possible correlations among these distributions. The second issue is the assertion that the better method is to calculate "based on the probability distribution of actual changes in operating reserves," which seems to imply looking at the past reserves data over the relevant interval.

The change in reserve availability will be affected by changes in generating capacity, including intermittent resources, and changes in load. If there is a material correlation between the components, this should be accounted for in the estimation of the probability distribution. Griffey asserts that the PJM proposal does not account for this correlation.[18] The most direct way would be to estimate the correlation as part of the review of historical data used to estimate the aggregate probability distribution. Griffey apparently assumes that the PJM proposal is to estimate the component load, wind, solar, etc. distribution separately across many periods, and then combine the estimates assuming independence of the component deviations. However, as explained in the Rocha Garrido Affidavit,[19] the actual PJM proposal is to combine the component errors period by period, which automatically accounts for any correlation in the historical data.

A consideration going forward will be the possible need to change the distribution to update for the changing mix of resources, so there should not be a constraint to use only backward-looking evidence. This would be a natural part of estimating and modifying the probability distributions to provide the best estimates for existing and future operating conditions.

The suggestion of using "actual changes in operating reserves" raises other questions. The probability distribution of changes in operating reserves is a relevant issue, but must be defined as the change in operating reserves from the sources defined at the start of the anticipated dispatch interval. Operating actions arising from out-of-market actions, including load curtailment, should not be included in measurements of changes in available operating reserves. Otherwise, the estimates would obfuscate the very problem PJM is trying to solve. Hence, the historical records of actual operating reserve changes should be purged of any such operator interventions. Griffey cites ERCOT as using the actual operating reserves.[20] To the extent this means dealing with the correlation problem by aggregating the contemporaneous historical observations on the generation and load, this is correct. But the ERCOT estimation excludes the "actual operating reserve" changes that are due to operator intervention. As described in the Rocha Garrido affidavit,[21] the

17 Affidavit of Charles S. Griffey on Behalf of The PJM Load/Customer Coalition, May 15, pp. 2-3.

18 Griffey Affidavit, March 29, p. 3.

19 Rocha Garrido Affidavit, March 29, p. 7.

20 Griffey Affidavit, March 29, p. 2.

21 Rocha Garrido Affidavit, March 29, p. 4.

components in the PJM proposal do not include operator actions to create reserves. PJM's proposal is consistent with the ERCOT approach and accounts for operator intervention in devising the probabilistic approach to reflect uncertainties on the system in the operating reserve demand curve.

Minimum Generation Conditions

The Direct Energy comments and the IMM reply[22] raise the issue of the appropriateness of the proposed operating reserve demand curve under minimum-generation conditions. In these circumstances, generators must be taken off-line to reduce total energy output, but there is a concern that loss of generation capacity will also reduce operating reserves and create a higher scarcity price, providing a conflicting incentive for generators to stay on line.

Minimum generation conditions do occur, so there is a reasonable question about the implications for pricing with the proposed reforms to the operating reserve demand curve. However, minimum generation conditions do not alter the facts and principles for formulation of the operating reserve demand curve, so this matter would require consideration of other pricing reforms in the PJM market.

The essential problem is that the Direct Energy analysis applies a line of argument about the appropriate incentives from scarcity pricing that makes implicit assumptions that the underlying market satisfies the simplifying assumptions of convexity. However, the minimum generation conditions of many generators are inherently non-convex in the requirement that they either produce a minimum amount or must go off-line. Under these conditions, there is no market-clearing price solution, either for energy or for reserves, that supports the optimal solution. This requires consideration of uplift payments for generators that are forced off line but would otherwise be profitable at the current prices.

Addressing the uplift-minimizing prices and associated uplift payments would be the right approach for dealing with this problem (Gribik, Hogan, & Pope, 2007). This is part of a separate agenda for PJM pricing reform. The solution to this special case is not to be found in modifying the characterization of the operating reserve demand curve.

Summary

The current PJM scarcity pricing mechanism does not meet the test of market efficiency and the requirements for a just and reasonable pricing model. The enhanced pricing proposal to address improved scarcity pricing through and Operating Reserve Demand Curve addresses a long-standing problem in the PJM market design. The focus is on improved operating incentives to

[22] Comments of Direct Energy in Support of Reserve Markets Price Formation Revisions, May 15, pp. 8-9, IMM, May 30, p. 21.

support the real-time supply and demand fundamentals. The PJM proposal calls for a workable implementation that within current reliability standards and practices. The implementation would be compatible with existing dispatch models. Collateral benefits include better information to support market power mitigation, improved opportunities for load participation, and a better balance between the capacity and real-time markets.

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[i] William W. Hogan is the Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University. This work was supported by PJM. This paper draws on research for the Harvard Electricity Policy Group and for the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Aquila, AQUIND Limited, Atlantic Wind Connection, Australian Gas Light Company, Avista Corporation, Avista Utilities, Avista Energy, Barclays Bank PLC, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator, California Suppliers Group, Calpine Corporation, CAM Energy, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, City Power Marketing LLC, Cobalt Capital Management LLC, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, COMPETE Coalition, Conectiv, Constellation Energy, Constellation Energy Commodities Group, Constellation Power Source, Coral Power, Credit First Suisse Boston, DC Energy, Detroit Edison Company, Deutsche Bank, Deutsche Bank Energy Trading LLC, Duquesne Light Company, Dyon LLC, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Authority New Zealand, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, Energy Endeavors LP, Exelon, Financial Marketers Coalition, FirstEnergy Corporation, FTI Consulting, GenOn Energy, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., GDF SUEZ Energy Resources NA, Great Bay Energy LLC, GWF Energy, Independent Energy Producers Assn, ISO New England, Israel Public Utility Authority-Electricity, Koch Energy Trading, Inc., JP Morgan, LECG LLC, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, MIT Grid Study, Monterey Enterprises LLC, MPS Merchant Services, Inc. (f/k/a Aquila Power Corporation), JP Morgan Ventures Energy Corp., Morgan Stanley Capital Group, Morrison & Foerster LLP, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario Attorney General, Ontario IMO, Ontario Ministries of Energy and Infrastructure, Pepco, Pinpoint Power, PJM Office of Interconnection, PJM Power Provider (P3) Group, Powerex Corp., Powhatan Energy Fund LLC, PPL Corporation, PPL Montana LLC, PPL EnergyPlus LLC, Public Service Company of Colorado, Public Service Electric & Gas Company, Public Service New Mexico, PSEG Companies, Red Wolf Energy Trading, Reliant Energy, Rhode Island Public Utilities Commission, Round Rock Energy LP, San Diego Gas & Electric Company, Secretaría de Energía (SENER, Mexico), Sempra Energy, SESCO LLC, Shell Energy North America (U.S.) L.P., SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, Transalta, TransAlta Energy Marketing (California), TransAlta Energy Marketing (U.S.) Inc., Transcanada, TransCanada Energy LTD., TransÉnergie, Transpower of New Zealand, Tucson Electric Power, Twin Cities Power LLC, Vitol Inc., Westbrook Power, Western Power Trading Forum, Williams Energy Group, Wisconsin Electric Power Company, and XO Energy. The views presented here are not necessarily attributable to

any of those mentioned, and any remaining errors are solely the responsibility of the authors. (Related papers can be found on the web at www.whogan.com).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket No. ER19-1486-000**
PJM Interconnection, L.L.C.	)	**Docket No. EL19-58-000**

VERIFICATION OF DR. WILLIAM W. HOGAN

Dr. William W. Hogan, being first duly sworn, deposes and states that he is the Dr. William W. Hogan referred to in the foregoing document entitled "Reply Affidavit of Drs. William W. Hogan and Susan L. Pope", that he has read the same and is familiar with the contents thereof, and that the testimony set forth therein is true and correct to the best of his knowledge, information, and belief.

Subscribed and sworn to before me, the undersigned notary public, this 13th day of June, 2019.

CLAIRE M BYRNE
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
July 9, 2021

Claire M. Byrne

Notary Public

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	))	**Docket No. ER19-1486-000**
PJM Interconnection, L.L.C.	))	**Docket No. EL19-58-000**

VERIFICATION OF DR. SUSAN L. POPE

Dr. Susan L. Pope, being first duly sworn, deposes and states that she is the Dr. Susan L. Pope referred to in the foregoing document entitled "Reply Affidavit of Drs. William W. Hogan and Susan L. Pope", that she has read the same and is familiar with the contents thereof, and that the testimony set forth therein is true and correct to the best of her knowledge, information, and belief.

Susan L. Pope

Subscribed and sworn to before me, the undersigned notary public, this 14th day of June, 2019.

Michael Piccione

Notary Public

Commonwealth of Massachusetts MP
County of Norfolk

On this 14th day of June, 2019, before me, the undersigned notary public, personally appeared Susan L. Pope, proved to me through satisfactory evidence of identification, which were MA DL, to be the person whose name is signed on the preceeding or attached document in my presence

MICHAEL PICCIONE
Notary Public, Commonwealth of Massachusetts
My Commission Expires March 06, 2026

My Commission Expires
March 6, 2026

Attachment B

Reply Affidavit of Adam Keech
on Behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. ER19-1486-000**
	)	
PJM Interconnection, L.L.C.	**)**	**Docket No. EL19-58-000**

REPLY AFFIDAVIT OF ADAM KEECH
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

I. Introduction

1. My name is Adam Keech. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I am the same Adam Keech that submitted an affidavit in this proceeding on March 29, 2019.[1] I am submitting this reply affidavit on behalf of PJM Interconnection, L.L.C. ("PJM") in support of its reserve market reforms in this proceeding. In this reply affidavit, I respond to protests and complaints regarding the potential impact of PJM's proposal to reform its Operating Reserve Demand Curves ("ORDC") and the simulated market outcomes I presented in my Initial Affidavit.

II. Simulations of Estimated Impact of PJM's Proposal

2. In their protest[2] to the March 29 Filing, the Independent Market Monitor ("IMM") argues that PJM's use of Case B as the relevant benchmark to measure the impact of PJM's Proposal is inappropriate. The IMM's claim regarding the case comparison seeks to inflate the impact of PJM's proposal to illustrate why they believe it is unreasonable. However, the IMM fails to support these claims with any rational argument, and thus statements misguide the record. The IMM states:

> PJM argues that the relevant comparison to assess the impact of the ORDC proposal is the comparison of Case B to Case C. Because Case B modifies actual PJM operating conditions, it is not an accurate base case. The comparison of Case B to Case C understates the impact of PJM's proposed changes on the actual market outcomes.[3]

[1] Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., Docket Nos. EL19-58-000, et al., at Attachment D (Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C. ("Keech Initial Aff.")) (March 29, 2019) ("March 29 Filing").

[2] Protest of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket Nos. EL19-58-000, et al. (May 15, 2019) ("IMM Protest").

[3] IMM Protest, Attachment B (ORDC Simulation Results: Version 2) at 2 ("IMM ORDC Report").

3. This is the clearest argument provided by the IMM to support their claim that the relevant base case to use to measure the impact of the PJM Proposal is Case A and not Case B as PJM has stated. But, it is not clear what this statement means or why it can be used as evidence that Case B is the inappropriate benchmark for comparison. Nonetheless, this is the only argument in the IMM's filing or report provided to support the argument that Case A should be used rather than Case B. In my Initial Affidavit I explained in detail why Case B is the relevant base case to use when measuring the impact of the PJM Proposal.[4] I will summarize that explanation again for clarity.

   a. The definition of Case A is contained in paragraphs 31 and 32 of my Initial Affidavit. As I previously explained, the purpose of Case A is to measure the impact of the removal of the Tier 1 product in isolation from the other proposed changes. The relevant information regarding this case for this discussion is that the when it was solved, the only resources that were allowed to have their commitment status changed in the simulation were combustion turbine ("CT") and diesel units that were not self-scheduled. All other units, including those manually committed by PJM for reliability, were only re-dispatched in the simulation. Their commitment states (on/off) remained the same as how they operated in real-time during 2018.

   b. In paragraphs 38-41 of my Initial Affidavit I explained in detail how Case B was executed and why it is the relevant case from which to measure the impact of the PJM Proposal. In short, Case B is a rerun of Case A with the full unit commitment optimized. This means that all units that are able to be committed by PJM will have their commitment state determined via the optimization done by the simulation software. This includes resources that PJM manually committed for reliability and those that were committed economically by PJM. It does not include resources that were self-scheduled, hydro resources, wind, solar, batteries, and landfill gas.

   c. Case C has the same unit commitment configuration as Case B but implements the PJM Proposal.

4. The IMM does not support their argument that Case A is the right base case for comparison to Case C. They rely on the aforementioned argument that Case B, "modifies actual PJM operating conditions",[5] which makes it an inappropriate base case. They fail to recognize that the same unit commitment modifications that are applicable to Case B are also applicable to Case C, because the unit commitment in Case C is done using the same process as Case B. This means

[4] Keech Initial Aff. ¶¶ 38-45.

[5] IMM ORDC Report at 2, 3.

that in Case C, like in Case B, all units that are able to be committed by PJM will have their commitment state determined by the simulation software as part of the optimization process. Like Case B, Case C can also de-commit resources committed by PJM for reliability. As a result, the only difference between Case B and Case C is the implementation of the PJM Proposal. If the goal is to measure the impact of the PJM Proposal, which is the purpose of these simulations, there is no better way to do this.

5. The IMM proposes using Case A and Case C to measure the impact. This has several fatal flaws, which the IMM overlooks. For clarity, I will provide them.

6. As an initial matter, the unit commitment processes in Case A and Case C are very different. Case A uses the existing real-time commitment state for all resources other than PJM-scheduled CT and diesel units which are re-optimized. This means that all non-CT and diesel units that ran in real-time in 2018 are also running during those same hours in the simulation case, regardless of whether they are needed or not. In Case C, only the resources that are actually needed based on real-time operating conditions are committed and dispatched.

7. In order for the impact of this unit commitment difference to be considered as part of the impact of the PJM Proposal, those commitment changes would have to be part of the PJM Proposal and not the status quo. Clearly, they are not. PJM's Proposal does not include performing a full unit commitment once real-time operating conditions are known. This would only be able to be done after-the-fact, which is physically impossible. Therefore, this impact is removed from the PJM Proposal via the use of Case B. Another way to view this is that the PJM Proposal would have to produce a day-ahead commitment that is exactly optimal for real-time operating conditions, which are unknown at the time the day-ahead commitment is performed. This is also impossible.

8. Further, Case A contains units that were committed by PJM for reliability reasons (i.e., transmission, etc.) whereas Case C will only commit those units if they are economic. PJM has never stated, despite the IMM's claims, that its reserve market proposal will result in the elimination of the need to commit resources for transmission. Conceptually that does not make sense. Assuming that this is the case for the purpose of measuring the impact of the PJM Proposal is inappropriate and should not be included as part of the impact of the PJM Proposal.

9. Thus, by making the comparison of Case B to Case C, it is easy to isolate the impact of the PJM Proposal because it is the only variable between the two cases and therefore there is nothing to pollute the results. It is true that both cases have fully optimal commitments based on real-time conditions rather than what actually ran during 2018. However, this is consistent across both cases and therefore cancels out when subtracting the results of Case B from Case C to determine the impact. Using Case A allows for the commitment process difference between Case A and Case C to be part of the impact, which is wrong.

III. Relative Impact of PJM's Proposal on Flexible and Inflexible Resources

10. The IMM states that PJM's proposed ORDCs, "provide[s] more benefits to inflexible resources than flexible ones."[6] However, the arguments offered in support of this claim are not stated clearly by the IMM (or by other protestors). Moreover, the data provided by the IMM[7] do not lead to this conclusion.

11. It appears that the concern that inflexible resources may benefit originates from the fact that the PJM Proposal will likely result in an increase in Locational Marginal Prices ("LMPs"), and those LMPs will be paid to all resources providing energy, even those that are not capable of providing reserves. The IMM and the PJM Load/Customer Coalition ("Load Coalition") view this as a flaw of the PJM Proposal that renders it unjust and unreasonable.[8] There are conceptual and empirical problems with this conclusion, as I explain below.

12. The market result of LMPs increasing when reserves are tight or short is not a new phenomenon. This principle underlies fundamental energy market design elements, such as shortage pricing. In Order No. 719,[9] the Federal Energy Regulatory Commission ("Commission") laid out options to accomplish effective shortage pricing in Independent System Operator ("ISO")/Regional Transmission Organization ("RTO") markets. One of these options was to use ORDCs to escalate energy prices during periods of reserve shortages.[10] PJM implemented shortage pricing in 2012 and has since had a market design that increases energy when reserves are scarce and ultimately when they are short.

13. Protestors purport that this rational market clearing outcome, in which energy prices escalate when reserves are scarce or short, incentivizes inflexibility. To reach this conclusion, however, the protestors make two fundamental errors. One, they inappropriately rely on the IMM's incorrect analysis in the IMM's ORDC Report. Two, they fail to recognize the stark difference in the scale of the energy market versus the reserve market. I address these errors next.

14. First, as explained above, the IMM's argument that Case A is the appropriate base case for measuring the impact of the PJM Proposal is incorrect and unfounded, as the IMM does not provide any strong logical or empirical support for it. Ascribing any weight to the IMM's arguments would shift the focus to Case A

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[6] IMM Protest at 47-49.

[7] *See id*. at 49, Table 3.

[8] IMM Protest at 7-12; *see* Protest of the PJM Load/Customer Coalition, Docket Nos. EL19-58-000, et al., at Attachment A, Affidavit of Ali Al-Jabir, at ¶ 12 (May 15, 2019).

[9] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,078 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[10] *See* Order No. 719 at P 208.

(instead of on Case B) which inappropriately inflates the reasonably estimated cost of the PJM Proposal.

15. Second, in the analysis I provided in my Initial Affidavit, I estimated an increase in energy market revenues of $366 million and an increase in reserve market revenues of $189 million. While the energy revenue increase is higher than the reserve market increase, it is important to keep in mind the scale of these two markets. The PJM energy market settles roughly 800,000 gigawatt hours ("GWh")/year, while the reserve market under the PJM Proposal would settle about 50,000 GWh/year. In short, the energy market is about sixteen times larger than the reserve market. Therefore, in a simplistic view, any price change in the energy market will generate sixteen times the amount of revenue that the same price change would create in the reserve market. For this reason, it is more appropriate to consider these changes on a percentage basis to gauge the impact of design changes, as it normalizes the sizes of the markets. When considering the PJM Proposal in this manner, the increase in energy market revenues is estimated to be 1.31% ($366 million) and the estimated increase in reserve market revenues is 404% ($189 million). This error is discussed further below where I discuss reserve market dysfunction in energy market terms.

16. Aside from their LMP-based concerns, the IMM's definition of flexible in their analysis is not clear. In the context of this proceeding, flexible resources are those that can provide the type(s) of reserve product that the PJM system needs, meaning that the resource has a dispatchable range and, when called upon, is capable of providing energy within 10 or 30 minutes (depending on the product). This definition of flexible resources is reasonable, and when considered, the IMM's analysis does not support their conclusion. For example, Table 9 in the IMM ORDC Report compares Case B to Case C to show the revenue increase and decrease by technology type.[11] If the total change in energy and reserve revenues is summed across all asset types that collected some amount of reserve revenues (i.e., the sum of the change in total revenues for each asset class where the increase in reserve revenues increase is greater than zero), then approximately 76.5% of the total revenue increase is paid to flexible units. If this same simple analysis is performed on Table 19 of the IMM ORDC Report, which is the IMM's inappropriate comparison between Case A and Case C[12] as the impact of the PJM Proposal, it still shows that 65.3% of the total revenue increase goes to resources that are flexible and providing reserves under the PJM Proposal.

17. Finally, the IMM argues that an increase in the LMP when reserves are scarce or short will incentivize inflexibility simply because those energy payments will, in-part, go to inflexible units. This is also incorrect. LMP incentivizes suppliers to sell or produce energy, but contains little in the way of directly incentivizing flexibility or inflexibility; rather, incentivizing flexibility is the province of the

[11] IMM ORDC Report at 9 (Table 9).

[12] *Id*. at 15 (Table 19).

reserve market. Consider an alternative scenario where 75% of the energy in PJM is provided by renewables. In this circumstance, would the argument be that an increase in the LMP during reserve scarcity incentivizes renewables? Such an argument would be irrational. Similarly, the argument that enhanced scarcity pricing incentivizes inflexibility is baseless.

IV. Reserve Market Dysfunction in Energy Market Terms

18. Because the Synchronized Reserve market revenues are quite small and there is a relatively small amount of uplift in comparison to the energy market, it is tempting to dismiss the current dysfunction in Synchronized Reserve market price formation as non-existent. However, reserve market prices send important signals to the market upon which future investment in reserve capability will be based. Further, regardless of the relative size of the market, it is important that prices are well formed, reflective of supply and demand fundamentals, and signal the value reserves provide to the system.

19. In 2018, just under $44 million were paid to resources providing Tier 2 Synchronized Reserves.[13] 53.8% of these credits ($23.7 million) were paid through Synchronized Reserve Market Clearing Price credits, while the remaining 46.2% of the credits ($20.3 million) were paid through uplift (i.e., Synchronized Reserve lost opportunity cost credits). The production cost of these Tier 2 Synchronized Reserves was $31.8 million dollars. Given that, by definition, uplift covers the portion of production costs that are not compensated via clearing price credits, this means that 63.9% of all production costs needed to be recovered via uplift payments. The remainder of the production costs (36.1%) were compensated through Synchronized Reserve Market Clearing Price Credits. This demonstrates that current reserve market pricing fails to capture the majority of the costs that are incurred in providing synchronized reserves; indeed, it captures only about one-third of the costs.

[13] *See* Monitoring Analytics, LLC, *2018 State of the Market Report for PJM*, at 470 (Table 10-18) (Mar. 14, 2019), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf ("2018 State of the Market Report").

Table 1: 2018 Tier 2 Synchronized Reserve Billing

	2018 RTO Synchronized Reserve Tier 2 Billing	Percentage of Total Billing	Percentage of Production Cost
Synch Reserve Clearing Price Credits	$23,688,299[14]	53.8%	36.1%[15]
Synch Reserve Lost Opportunity Cost Credits (Uplift)	$20,306,909[16]	46.2%	63.9%
Total Tier 2 Billing	$43,995,208		
Total Tier 2 Production Cost	$31,776,541		

20. In order to appreciate the scope of dysfunction in current reserve market price formation, it is helpful to consider what energy market price formation would look like if the energy market displayed the same dysfunction as the Synchronized Reserve market. If 46.2% of all energy market revenues were paid in the form of uplift, and 63.9% of energy market production costs were recovered via uplift, as they are in the Synchronized Reserve market, the energy market would stand in very stark contrast to its current form. In reality, in 2018, only 0.3% of all energy market credits were paid through uplift while only 0.8% of production costs were recovered via uplift.

21. The following hypothetical demonstrates the severity of the market distortion that currently exists in the Synchronized Reserve market by applying the Synchronized Reserve market billing and production cost ratios to the energy market.

[14] *Id*. (Table 10-18).

[15] The percentage of production costs covered by Synchronized Reserve clearing price credits is covered by subtracting the percentage of production costs covered by uplift from 100%. The $23.7 million in Synchronized Reserve Clearing Price Credits for 2018 covered this remaining portion of the production costs, plus provided some infra-marginal rents.

[16] *Id*.

Table 2: Assumptions for Hypothetical

Assumption	Value	Source
Annual load megawatt hour ("MWh")	791 million[17]	2018 PJM Annual Report
Energy production cost	13.1 billion[18]	Simulation Case B
% of production cost paid through LMP	36.1%	Assumes the 2018 reserve market ratios apply to the energy market
% of production cost paid through uplift	63.9%	
% of total energy market credits paid through LMP	53.8%	
% of total energy market credits paid through uplift	46.2%	

22. Using these assumptions, you can then estimate what the energy market credits, uplift, and average LMP would be if the energy market followed the same market revenue and uplift patterns as the Synchronized Reserve market.

Step 1: Calculate the amount of production cost that is paid through LMP versus uplift.

Amount of production cost covered by LMP credits = Energy Production Cost * % of production cost paid through LMP

Uplift = Production Cost – Amount of production cost covered by LMP credits[19]

23. Assuming that the energy market mimics the reserve market in covering only 36.1% of production costs via LMP, LMP credits would have only covered $4.7 billion of the $13.1 billion in energy market production costs. Because any

[17] 2018 State of the Market Report at 16 (Table 1-8).

[18] Total energy market production costs are not readily available from PJM's production market clearing engines because the commitments happen across several market clearing engines. In lieu of the actual value, the production cost from PJM's simulation Case B can be used as a proxy for actual production costs. Although the actual production cost almost certainly varies from the simulation production cost, it is reasonable to assume that the numbers are of similar scale and use of the simulation production cost yields the same message in the end.

[19] An alternative yet equivalent way to calculate this value is to multiply the $13.1 billion energy market production cost by the percentage of production costs recovered via uplift.

production costs not recovered via LMP credits will be recovered via uplift, uplift would be equal to the remaining $8.4 billion of production costs.

Step 2: Calculate total energy market billing (LMP credits plus uplift)

Total energy market billing = Uplift / % of total energy market credits paid through uplift

24. Assuming that the energy market mimics the reserve market in the percentage of all energy market revenues provided through uplift payments, the $8.4 billion in uplift credits determined in Step 2 would represent 46.2% of the total energy market billing. Total energy market billing would therefore be $18.2 billion.

Step 3: Calculate LMP credits

LMP Credits = Total energy market billing - Uplift

25. In this simplified example, total energy market billing equals LMP credits plus uplift. With $18.2 billion in total energy market billing, as determined in Step 2, and $8.4 billion in uplift, as determined in Step 1, LMP credits would equal the residual $9.8 billion.

Step 4: Calculate average LMP

LMP = LMP Credits / Load

26. Assuming that generation and load are generally in balance, annual load MWh is a good proxy for the MWh of generation that was credited through LMP. The annual average LMP can therefore be approximated by dividing the $9.8 billion in LMP credits determined in Step 3 with the 2018 annual load of 791 million MWh, which results in an LMP of $12.39/MWh.

27. The table below summarizes the results of this hypothetical and compares it to actual 2018 energy market billing. Applying the revenue distribution patterns that exist in the reserve market to a market as large and prominent as the energy market makes the severity of the dysfunction in reserve market pricing quite apparent. Under this scenario, the average LMP would be approximately $26/MWh (or 68%) less than the average load weighted LMP for 2018. Further, uplift would increase by 8,300%. Infra-marginal rents would decrease by 71%, creating further reliance on the capacity market to cover fixed operating costs and provide incentives for continued resource investment.

Table 3: Summary of Outcomes from Hypothetical

	2018 Energy Market (billions)	Hypothetical 2018 Energy Market (billions)	Difference (Hypothetical minus 2018) (billions)	% Change
LMP Credits ($)	30.3[20]	9.8	-20.5	68%
Uplift ($)	0.1[21]	8.4	8.3	8300%
Total energy market billing ($)	30.4	18.2	-12.2	-40%
Energy Production Cost ($)	13.1	13.1	0	0%
Amount of production cost covered by LMP credits ($)	13.0[22]	4.7	-8.3	-64%
Inframarginal Rents[23] ($)	17.3	5.1	-12.2	-71%
LMP	$38.24/MWh[24]	$12.39/MWh	$-25.85/MWh	-68%
% Production Cost paid through clearing price	99.2%	35.9%[25]	-63.3%	-64%
% of Production Cost paid through uplift	.8%	64.1%	63.3%	8297%
% Total credits paid through LMP	99.7%	53.8%	-45.9%	-46%
% Total credits paid through uplift	0.3%	46.2%	45.9%	13945%

28. The hypothetical demonstrates the relatively significant scope of the present dysfunction in the reserve market. If the same level of inefficiency that exists in the reserve market was found in the energy market, it would not be tolerated, and would be found unjust and unreasonable immediately. The fact that the reserve

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[20] 2018 State of the Market Report at 16 (Table 1-8).

[21] *Id*. at 219 (Table 4-1). Sum of Day-Ahead and Balancing Uplift (excluding Balancing Lost Opportunity Cost Credits).

[22] Energy production cost minus uplift.

[23] Infra-marginal rents are calculated as the difference between total energy market billing and production cost.

[24] 2018 State of the Market Report at 16 (Table 1-8).

[25] Slight differences exist between the percentages shown here for the hypothetical energy market result and the original synchronized reserve market percentages upon which the example is based. This is due to rounding the figures throughout the example in order to simplify the numbers and make the example easier to digest.

market is much smaller than the energy market and results in only $20 million in uplift as opposed to $8.4 billion does not make the price formation dynamics in the reserve market acceptable. Reserve market uplift is substantial relative to the size of the reserve market, and provides further evidence of the need for reserve market reforms.

V. Value of Reserves Beyond the MRR

29. A primary issue in this proceeding is determining what value reserves have in excess of the minimum reserve requirements ("MRR"). Considering the significant evidence put forth by PJM regarding forecast uncertainty and operator biasing, it is evident and clear that the value is not zero. By accepting PJM's current-effective ORDC, the Commission has already accepted that reserves beyond the MRR have a value above zero in PJM. It is also clear through PJM's analysis in its initial filing that the value of the next megawatt ("MW") of reserves declines as the current quantity increases. This results in the downward-sloping demand curve (i.e., a tail to the ORDC) that is proposed. In the co-optimization context (like how PJM clears the energy and reserves markets), it represents a benefit function that describes the value added to consumers by procuring a specific reserve quantity.

30. As described in the March 29 Filing, the benefit added to consumers is a function of the probability of being unable to meet the MRR in a certain timeframe given a certain amount of reserves, and the of the emergency action system operators will take to restore reserves (i.e., the penalty factor). This varying benefit is represented by the shape of PJM's proposed ORDCs. When the benefit of some of those excess reserves is lost because they are converted into energy, it lessens PJM's ability to manage additional uncertainty and therefore is an impact to reliability, albeit a small impact for significant amounts of reserves. This manifests in the market as an increase in the marginal cost of energy resulting in a portion of the estimated $0.46/ MWh increase in PJM's analysis. If the marginal cost of energy increases, it is paid to those supplying energy, regardless of their level of flexibility, technology, or fuel type. That is how a single-clearing price market works.

31. Nonetheless, the IMM contends that "PJM's need to maintain reserves does not necessitate that reserve prices exceed zero at all times, or even the majority of the time."[26] While PJM agrees with the IMM's assertion that zero is an efficient market price when supply and demand conditions warrant it, the fact is that reserve market prices in PJM are zero in an inordinate amount of hours because of market deficiencies, not because of supply and demand conditions. As PJM has demonstrated, the current reserve market does not accurately depict the supply or demand for reserves at any given time and as a result produces a zero price in a significantly higher amount of hours than it should.

[26] IMM Protest at 13.

32. Table 4 below shows the percentage of hours where the average clearing price for Synchronized and Non-Synchronized Reserves was zero in 2018. The first data row of the table contains the hourly average clearing prices from the actual market results in 2018, the second row was calculated from the simulation Case C that PJM submitted with its original filing.[27] The market results from 2018 show that the Synchronized Reserve Market Clearing Price is zero in about 56.8% of the hours and the Non-Synchronized Reserve Market Clearing Price is zero for 97.5% of the hours. In Simulation Case C where the supply curve for reserves does not rely on Tier 1 and the demand curve incorporates the modeled uncertainty proposed by PJM, those percentages drop precipitously.[28]

Table 4: Percentage Of Hours Where The Average Clearing Price For Synchronized And Non-Synchronized Reserves Was Zero In 2018

Category	Percentage of Hours When Synchronized Reserve Market Clearing Price = $0/MWh	Percentage of Hours When Non-Synchronized Reserve Market Clearing Price = $0/MWh
2018 Market Results - Percentage of Hours	56.8%	97.5%
Simulation: PJM Proposal (Case C) - Percentage of Hours	8.8%	9.7%

33. Zero prices for reserves, or any product for that matter, are acceptable when the market conditions warrant it. However, the reserve markets in PJM have been proven to be dysfunctional because of market elements such as Tier 1 reserves, the roughly 50% of the market that is settled through uplift payments, and the consistent need for operators to bias dispatch tools to maintain reserve adequacy. Based on the statistics in Table 4, this faulty market design generally produces more zero prices for reserves when they are not appropriate, but also likely results in the opposite problem in some cases as well.

34. From the supply perspective in the Synchronized Reserve and Primary Reserve markets, the markets are skewed by the use of Tier 1 Synchronized Reserves. As stated in the March 29 Filing, the performance of Tier 1 is poor (about 60% of what is estimated actually responds),[29] and as the IMM states in their protest, other resources on which PJM has not estimated Tier 1 may respond as well.[30] PJM agrees with the IMM on this point. It illustrates the difficulty in constructing an accurate supply curve when a significant portion of the reserve has no obligation to respond. At any given time, PJM's Tier 1 estimate may be too high

[27] The 2018 Market Results shown in the first data row are calculated using the same days that were reported in the simulation results. There were ten days in the simulation results that were removed due to data issues. PJM excluded these same ten days when calculating the metrics for the 2018 Market Results.

[28] Simulation Case C also includes the optimal unit commitment based on real-time conditions. This will result in a lower number of zero-priced hours than will likely be observed in real-time due to a reduction in the available reserves provided by uneconomic generator commitments.

[29] March 29 Filing at 18-19.

[30] IMM Protest at 16.

or too low but what can be guaranteed is that it is wrong. The use of the Tier 1 product as part of the Synchronized and Primary Reserve supply curves makes it virtually impossible to calculate accurate prices.

35. From the demand perspective, the current stepped ORDCs do not incorporate the additional complexity and need for reserves that uncertainty creates for system operators. The result is a demand for reserves that is too low which results in operator biasing of the dispatch tools. The general dynamic of a supply curve that is artificially flat, due to Tier 1 and a demand curve that is artificially short due to the lack of including uncertainty in the reserve demand, creates an environment where reserves are generally undervalued and results in artificially low reserve prices and a significant percentage of the market settled through uplift.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket No. ER19-1486-000**
	)	
PJM Interconnection, L.L.C.	)	**Docket No. EL19-58-000**

VERIFICATION OF ADAM KEECH

Mr. Adam Keech, being first duly sworn, deposes and states that he is the Mr. Adam Keech referred to in the foregoing document entitled "Reply Affidavit of Mr. Adam Keech," that he has read the same and is familiar with the contents thereof, and that the testimony set forth therein is true and correct to the best of his knowledge, information, and belief.

Adam Keech

Subscribed and sworn to before me, the undersigned notary public, this 21st day of June 2019.

Linda Spreeman
Notary Public

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

Attachment C

Reply Affidavit of Christopher Pilong on Behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. EL19-58-000**
	)	
PJM Interconnection, L.L.C.	**)**	**Docket No. ER19-1486-000**

REPLY AFFIDAVIT OF CHRISTOPHER PILONG
ON BEHALF OF PJM INTERCONNECTION, L.L.C

1. My name is Christopher Pilong. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I am same Christopher Pilong that submitted an affidavit in this proceeding on March 29, 2019.[1] I am submitting this reply affidavit on behalf of PJM Interconnection, L.L.C. ("PJM") in support of its reserve market reforms in this proceeding.

<u>Response to the Maryland PSC</u>

2. In response to the Maryland PSC Comments,[2] there are a few items that should be clarified. First, the Maryland PSC correctly notes that there is a difference in annual response of Tier 1 vs Tier 2 of 16% (66.2% for Tier 1 vs 82.4% for Tier 2), but implies that this is not a significant difference.[3] However, a 16% average shortfall of Tier 1 vs Tier 2 amounts to roughly 232 megawatts ("MWs"), when compared to the average synchronized reserve requirement of 1450 MWs. That *is* a significant amount of MWs when talking about reserves necessary to reliably operate the PJM system in compliance with the North American Electric Reliability Corporation's mandatory Reliability Standards. Consolidating the two products into one single product with consistent performance obligations is an important step in addressing this disparity.

3. Second, the Maryland PSC incorrectly assumes that PJM is deficient in providing its dispatchers with proper information.[4] This is simply untrue. The information and calculations presented to the dispatchers are as accurate as possible. However, there is an important distinction between Tier 1 and Tier 2 reserves that the Maryland PSC overlooks but must be emphasized. Tier 1 is an *estimate* of the expected voluntary response from a generator, based on a combination of the Generator Operator-submitted parameters, coupled with PJM adjustments to the submitted ramp rate. This estimate is then presented to the dispatchers and is tracked against when comparing the Tier 1

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[1] Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., Docket Nos. EL19-58-000, et al., at Attachment E (Affidavit of Christopher Pilong on Behalf of PJM Interconnection, L.L.C. ("Pilong Initial Aff.")) (Mar. 29, 2019) ("March 29 Filing").

[2] Maryland Public Service Commission Protest and Comments, Docket Nos. EL19-58-000, et al. (May 15, 2019) ("Maryland PSC Comments").

[3] *Id.* at 4-5.

[4] *Id.* at 5.

response rate. This is shown in the IMM data referenced in my initial affidavit,[5] and denoted by the column header "Tier 1 estimate (MW Adj by DGP)," where "DGP" is the degree of generator performance adjustment applied to the ramp rate. It is important to note that the estimate of response is not a calculation of actual capability of the resource. It is estimated, because without an assignment and obligation, generators cannot be relied on to respond, and history has shown that they do not respond. Even with the reduced estimated response, Tier 1 resources still only respond with an average 66.2% response rate.

4. Conversely, Tier 2 is *not an estimate*. Tier 2 is an assignment of a reserve commitment that is based purely on the submitted Generator Operator parameters, and is not adjusted by PJM in any fashion. It is a simple calculation that reflects the MWs a unit is physically capable of moving in ten minutes.

5. It should also be noted that in addition to the ramp rate adjustment, PJM has permanently excluded certain resources from being estimated for Tier 1 response, based on historical response failure. This adjustment, in addition to the aforementioned DGP adjustment, is employed to ensure that the PJM dispatcher has the best reasonable estimate of the response it can expect from resources, should the reserves need to be deployed to support the reliability of the PJM system.

6. However, there are unavoidable market implications that result. When PJM is forced, for reliability reasons, to adjust Generator Operator Market data and therefore market outcomes, the market is, by definition, not working as intended. Consolidation of Tier 1 and Tier 2 into one product eliminates the need to adjust market data, eliminates the need for estimating Tier 1, greatly improves the information available to the dispatcher, and results in a more transparent and efficient market overall.

<u>Response to the PJM Load/Customer Coalition</u>

7. The PJM Load/Customer Coalition takes issue with the data provided by PJM for the January 30–31, 2019 cold snap, and, citing PJM's reserve margin, concludes that "while temperatures were cold and loads were higher, the PJM system was not experiencing operating conditions properly characterized as 'tight' or 'stressed.'"[6] In doing so, the PJM Load/Customer Coalition completely ignores one of the foundational reasons that necessitated PJM's filing in the first place—operator bias. The PJM Load/Customer Coalition's inability to observe overt evidence of "tight" or "stressed" operating conditions is a direct result of PJM operators dramatically increasing their biases on these January dates.

8. To illustrate this point, I am sponsoring the following data, which tracks closely to the informational categories of "Table 1" included in my initial affidavit.[7] Note the

[5] Pilong Initial Aff. ¶ 26 n.6.

[6] Protest of the PJM Load/Customer Coalition, Docket Nos. EL19-58-000, et al., at 19 (May 15, 2019) ("PJM Load/Customer Coalition Protest").

[7] Pilong Initial Aff. at Table 1.

significant increase in bias by PJM operators for January 30–31, 2019, when compared with those same days in 2018.

	2018				January 30 - 31, 2019				Difference (Jan 30-31 minus 2018)	
Synchronized Reserves Surplus	Intervals	Percentage of Intervals	Average Operator Positive Bias (MWs)	Percentage of Intervals (Bias Removed)	Intervals	Percentage of Intervals	Average Operator Positive Bias (MWs)	Percentage of Intervals (Bias Removed)	Average Operator Positive Bias (MWs)	Percentage of Intervals (Bias Removed)
< zero MWs	2955	2.80%	1471	29.1%	23	4.0%	1500	44.4%	29	15.3%
zero to 250 MWs	18475	17.60%	558	13.3%	61	10.6%	1700	9.2%	1142	-4.1%
250 MWs to 500 MWs	25051	23.80%	531	15.2%	99	17.2%	1328	12.7%	797	-2.5%
500 MWs to 1,000 MWs	32005	30.40%	482	20.4%	196	34.0%	1701	14.9%	1219	-5.5%
greater than 1,000 MWs	26634	25.30%	408	21.9%	197	34.2%	2048	18.8%	1640	-3.2%

Synchronized Reserves Surplus	Intervals	Percentage of Intervals	Average Operator Positive & Negative Bias (MWs)	Percentage of Intervals (Bias Removed)
< zero MWs	23	4.0%	1906	42.0%
zero to 250 MWs	61	10.6%	272	6.0%
250 MWs to 500 MWs	99	17.2%	-5	9.0%
500 MWs to 1,000 MWs	196	34.0%	-250	12.0%
greater than 1,000 MWs	197	34.2%	-434	31.0%

9. Without these actions, the healthy reserve margin that the PJM Load/Customer Coalition predicates its conclusion on would not be possible. However, the fact that PJM operators needed to take such actions in the first place is compelling evidence that the market mechanisms designed to procure and deliver reserves are inadequate and need to be reformed.

10. With respect to the Affidavit of Rao Konidena on Behalf of the PJM Load/Customer Coalition,[8] Mr. Konidena raises important points about the rigor of the reviews, analysis, and training that the Midcontinent Independent System Operator, Inc. ("MISO") operators undergo to ensure that they are maintaining accurate forecasts and minimizing operator intervention. PJM agrees with these practices, as they are important to operate both a reliable and efficient system. While not specifically mentioned in the initial filing, PJM also performs similar reviews and analysis with the same goals in mind. PJM utilizes a Daily Review Team and report that scores the following items: Balancing Authority ACE Limit performance, Control Performance Standard 1 performance, regulation utilization and performance, load forecast accuracy, System Operating Limit/Interconnected Reliability Operating Limit control, Market-to-Market coordination activities (New York Independent System Operator, Inc. and MISO), uplift, generator outage rates (planned and forced), Real-Time and Day-Ahead Locational Marginal Price convergence, Security Constrained Economic Dispatch ("SCED") case approvals, and SCED min and max biases utilized. This report is distributed to Dispatch, Operations and

[8] PJM Load/Customer Coalition Protest at Attachment E.

Markets staff, and leadership daily. The report is verbally reviewed each day at an 8:45 morning meeting held with support staff and dispatch leadership, including the Dispatch Shift Supervisor scheduled for that day. The review is designed to quickly identify any anomalies in system forecasting and control for a quick resolution.

11. In addition to the daily reviews, the PJM Dispatchers receive an abundance of training. They undergo an eighteen-week training program that includes weekly training objectives utilizing a systematic approach to training that is overseen by the System Operator Training department and a qualified Instructor. The conclusion of the training is a written exam and simulation to exercise and confirm that the Dispatcher is qualified at all tasks. Once qualified, all Dispatchers have one out of every six weeks dedicated to training. As part of this training week, there is a standing dedication session held by PJM's Markets Coordination Department to review the efficiency of operations from a markets-based perspective, which includes reviews of uplift trends, case biasing, and real-time pricing.

12. Mr. Konidena concedes that even with training and improved tools, operator manual intervention to commit additional reserves cannot be eliminated in real-time operations, because of the inherent uncertainties in system forecasts. Again, PJM agrees with Mr. Konidena on this point. However, PJM disagrees on the value that should be placed on these reserves. PJM believes they provide material value and should be priced accordingly in PJM's market.

Response to the IMM

13. The IMM makes several points that serve to provide further education on the role of Immediate Term ("IT") SCED and how PJM operators bias the load in the case to account for all of the potential uncertainties that could lead to a real-time shortage of reserves if not considered and planned for by the dispatcher when making their real-time commitments of flexible resources. These are useful comments that help provide additional background and context. However, the IMM also indicates that the PJM analysis on the positive biasing impacts was somehow misleading, which is not an accurate statement. First, in my initial affidavit included in PJM's March 29 Filing, it is clearly stated that the biasing analysis is a worst-case scenario that assumes the operators took action based on the recommendations of the biased IT SCED case. Specifically, I stated at paragraph 16 that "[t]o be clear, this would represent a worst-case scenario level of reserves because the original positive bias would have had to result in additional commitment recommendations from the IT SCED that the operator took action on."

14. In addition, the IMM's focus on negative bias does not impact the analysis that PJM provided. PJM's analysis looked exclusively at the intervals where the bias was positive (as a percentage of the total number of intervals), and demonstrated that if the positive biases were removed in those cases, PJM could have been short reserves. The fact that negative biases existed in other cases does not change this statistic in any way. Moreover, the purposes of negative biasing and positive biasing are different. Specifically, when load is going out, PJM needs to begin taking resources offline. To prepare for this, the Dispatcher will negatively bias the case to see what units are on the

threshold of being recommended to be released (taken off-line), which allows the Dispatcher time to study and then eventually begin taking those units off as the actual system load reduces. While the practice of biasing the IT SCED case is similar on the surface, the actual purpose when compared to positive biasing during periods of increasing system load is fundamentally different. That is because the purpose of positive biasing is to maintain reserves and reliability during periods of increasing load (managing risk), and the purpose of negative biasing is to remove generation that is not economically needed after PJM has past the peak load for the period (managing uplift).

15. The purpose of the analysis was to show that operator biases will lead to additional IT SCED Combustion Turbine ("CT") recommendations. Those recommendations are acted upon to commit additional reserves. Those additional reserves, if needed, will set the price appropriately. However, if the IT SCED case (biased or unbiased) recommends CTs that the dispatcher commits and ultimately are not needed, even if there is only 1 MW of excess on the system, the Real-Time SCED and Locational Price Calculator pricing algorithms will set the reserve price to $0. When a product has a zero price, the inference is the product has zero value. However, when that MW was committed based on the IT SCED recommendation, it did have a value to the Dispatcher. The value was the hedge against the uncertainty discussed throughout PJM's initial filing. The IMM appears to agree with the concept that reserves committed in advance of the operating period have value and should be priced, noting at page 5 of its May 30, 2019 answer that "[t]he Market Monitor supports the explicit pricing of defined operator actions through the ORDC" and that "[o]perator actions to increase reserves should not suppress prices exactly when they need to increase."

16. This concludes my affidavit.

Attachment D

Reply Affidavit of Dr. Patricio Rocha Garrido on Behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. EL19-58-000**
	)	
PJM Interconnection, L.L.C.	**)**	**Docket No. ER19-1486-000**

REPLY AFFIDAVIT OF DR. PATRICIO ROCHA GARRIDO
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Dr. Patricio Rocha Garrido. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I am a Senior Engineer in Resource Adequacy Planning in the System Planning division of PJM Interconnection, L.L.C. ("PJM"). On March 29, 2019, I submitted an affidavit on behalf of PJM in support of its reserve market reforms in this proceeding.[1] In this reply affidavit, I respond to various criticisms of PJM's proposal to reform its Operating Reserve Demand Curves ("ORDCs").

<u>Arguments that Reserves Beyond the MRR Do Not Have Value</u>

2. PJM showed in its March 29 Filing that the current PJM ORDC and reserve market are not reasonable because they do not properly recognize the operational value of reserves. We showed that the current ORDC is not well designed to reflect that operational value in the face of uncertainty, and that reserve clearing prices of zero in the great majority of hours confirm that reserves are not appropriately valued in the current market. The Independent Market Monitor ("IMM") objects that PJM is confusing its operational need for reserves with efficient market prices, and that zero prices may simply reflect economic fundamentals.

3. However, the IMM is confusing the concepts of value and price. Reserves indeed have inherent value, and that reserve value is exactly what a properly designed ORDC should attempt to capture. Price is certainly determined by supply and demand conditions, but in the reserve market, demand is represented by the ORDC, so if the current ORDC does not properly value reserves, then prices resulting from using the current ORDC are not reflective of reserves' inherent value to the system.

4. If a zero price were the result of using a demand curve (the ORDC) for the reserve product that is just and reasonable, PJM would agree with the IMM. However, the current ORDC is unjust and unreasonable because it does not account for all the real-time uncertainties that are present every time a Real-time Security Constrained

[1] Affidavit of Dr. Patricio Rocha Garrido on Behalf of PJM Interconnection, L.L.C. ("Rocha Garrido Initial Aff.") (Attachment F to Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., Docket Nos. EL19-58-000, et al. (Mar. 29, 2019) ("March 29 Filing")).

Economic Dispatch ("RT SCED") is run. These uncertainties provide value to reserves in excess of the minimum reserve requirement ("MRR").

5. The IMM also challenges the very idea of a non-zero price for reserves beyond the MRR, arguing that, while shortage pricing during a reserve shortage is important, shortage or scarcity pricing is unnecessary in the absence of shortages. The IMM is correct that shortage pricing is important, which is why if reserves fall short of the MRR, the penalty factor is triggered, sending a strong price signal. But the IMM is not correct that scarcity pricing is unnecessary in the absence of shortages (i.e., when reserves are greater than the MRR) because the procurement of reserves occurs ex-ante, subject to uncertainties. If there were no uncertainties, PJM would agree that reserves beyond the MRR have zero value. However, uncertainties are present every time an RT SCED case is run.

6. Accordingly, a non-zero price for reserves beyond the MRR reflects the reality that such reserves have value, and that value is related to the magnitude of the real-time uncertainties in the PJM system. The IMM presents a stylized supply and demand graph in service of his argument,[2] but it merely assumes that reserves in excess of the MRR have no value. By refusing to recognize any value in reserves above the MRR, the IMM simply defines as inefficient any increase in energy prices resulting from reserve prices that *do* recognize that value. Once it is accepted that reserves beyond the MRR have value—because uncertainty persists beyond the MRR—the IMM's stylized construct is shown to be wrong. If reserves are reasonably priced, i.e., reflecting their value, then the energy prices resulting from co-optimization of energy and reserves also are reasonable, because they simply reflect and price the trade-off between providing energy and reserves.

7. Continuing with its challenge to the value of reserves beyond the MRR, the IMM argues that a sloped ORDC design like that proposed here by PJM assumes the reserve requirement is "not satisfied"[3] until the tail end of the ORDC; and this "persistent scarcity pricing"[4] sends load incorrect and inefficient signal to curtail.

8. However, the need for reserves in a system is rooted in uncertainties; if no uncertainties are present, then no reserves are needed. Prices should therefore be driven by the magnitude of such uncertainties. Recognizing this, PJM's proposed ORDC contains a downward sloping section that is based on historical PJM uncertainty data. What the IMM calls "persistent scarcity pricing"[5] is simply a recognition of the objective, historical fact that some level of real-time uncertainty remains at all reserve levels. Dropping the price to zero at any point on the curve embodies a conscious design choice to ignore the actual real-time uncertainties

[2] Protest of the Independent Market Monitor for PJM, Docket Nos. EL19-58-000, et al., at 24, Figure 4 (May 16, 2019) ("IMM Protest").

[3] *Id.* at 22.

[4] *Id.* at 23.

[5] *Id.*

beyond that point. As Drs. Hogan and Pope explain in their Reply Affidavit,[6] the fact there is scarcity pricing along the whole curve is not problematic and just reflects that reserves beyond the MRR improve reliability and lower the chance of incurring shortage costs.

9. While the IMM insists that the ORDC should be vertical at the MRR, i.e., reserves beyond the MRR should be priced at zero, the IMM suggests that the MRR can be increased, and the vertical curve shifted to the right, when additional flexibility is needed. Such proposed shifting of a vertical curve to the right, however, would only perpetuate the same issues PJM seeks to address through a downward-sloping ORDC, for two key reasons.

10. First, the IMM proposes that the magnitude of each instance of a rightward shift in the vertical ORDC would be "a result of operator actions to procure additional reserves based on operator uncertainty, inaccurate forecasts, or conservative operations."[7] Hence, under the IMM's proposal, the resulting reserve procurement and price would depend upon and reflect the subjective assessments of uncertainty made by individual operators. PJM operators ably perform their essential reliability role, but tying reserve prices so directly to individual operators' assessments of uncertainty is clearly not the best market design. A much better approach, like that proposed here by PJM, is to employ a systematic objective method of quantifying the uncertainty (based on historical errors and forced outages) which is then reflected in the downward sloping section of the curves. Uncertainties are not a rare phenomenon, they are present every time an RT SCED case is run. Hence, it is preferable to rely for market purposes on a transparent, systematic, objective methodology for quantifying uncertainty, rather than relying on subjective assessments of individual operators.

11. Second, the IMM's proposed episodic rightward shift in a vertical ORDC would not be accompanied by an assessment of the probability of the relevant uncertainty. Without accounting for the probability, the reserve procurement will occur at the same higher price for every megawatt ("MW") of additional reserves, exacerbating the effect of any miscalculation of uncertainty by individual operators.

12. For example, assume that the MRR is 1,500 MW and the penalty factor is $2,000/MWh. Under the IMM's suggested approach, if an operator believes the load forecast is understated by 500 MW, then she would increase the MRR by 500 MW, and thereby also shift the vertical ORDC to the right by 500 MW. The adjusted MRR would then be 2,000 MW (i.e., 1,500 MW + 500 MW). However, under this approach the penalty factor at that new 2,000 MW MRR would remain at $2,000/MWh. In contrast, under a downward sloping ORDC like that proposed by PJM, the price of reserves at 2,000 MW is properly recognized as being lower than the price of reserves at 1,500 MW. The operator is not certain the load forecast is understated by 500 MW. Accordingly, the proper approach is to estimate the

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[6] Hogan & Pope Reply at 6-7.

[7] IMM Protest at 15.

probability that the load forecast is understated by 500 MW, and then reflect that probability in the ORDC price associated with a reserve procurement of 2,000 MW. Because that probability is less than 100 percent, the ORDC price at 2,000 MW is reasonably set at less than the ORDC price at 1,500 MW.

Arguments that PJM Should Rely on the Current Curve's Step 2A and 2B

13. Several parties argue that PJM should rely on the current ORDC's steps below the MRR (i.e., Step 2A and Step 2B), instead of adopting a downward-sloping curve. However, while those steps reflected appropriate initial movement toward the principle that reserves beyond the MRR have non-zero, but reduced, value, those steps did not attempt to estimate the key driver of that value, i.e., recognizing and managing real-time uncertainties. Reserve markets are needed because of uncertainties. If no uncertainties existed and the future were fully known, then it could be argued that reserves are not needed. Unfortunately, uncertainties do exist. None of the parties urging continued reliance solely on the existing ORDC steps argues (or can argue) that they were designed to track the uncertainties that actually exist at reserve levels beyond the MRR. By contrast, for its proposed ORDCs, PJM is systematically and objectively quantifying the real-time uncertainties that drive the need for reserves, and is deriving demand curves based on those uncertainties.

Arguments that PJM's Proposed ORDC Methodology Does Not Reasonably Estimate the Uncertainty of Falling Below the MRR

14. As explained in detail in my Initial Affidavit,[8] PJM's methodology to determine the shape of the curve uses the most recent three years of historical data on variations between forecast (or expected) values and actual values for forecasts of load, interchange, solar generation, and wind generation, combined with historical data on thermal plant outages and regulation requirements, to estimate near-term uncertainties that warrant reserve procurement. Parties take issue with a number of aspects of this part of PJM's proposal. First, some parties argue that PJM's method overstates uncertainty because forecasts can be wrong in both directions, and thus could prevent rather than create shortages.[9] I addressed this issue in my Initial Affidavit at paragraph 20a. As I explained, there is a non-zero probability that the MRR is met ex-post even if there is an ex-ante MRR deficiency. If this non-zero probability were to be used in the ORDC development, then reserve prices associated with quantities below the MRR would be below the penalty factor because there is a non-zero chance that the net-load forecast error will turn out in PJM's favor. In other words, if this non-zero probability were to be used in the ORDC development, then the associated reserve price when PJM is experiencing a reserve shortage would be less than the penalty factor. This is inconsistent with operating the grid securely and reliably.

[8] Rocha Garrido Initial Aff. ¶ 15(a).

[9] IMM Protest at 38-40.

15. Instead, given the importance of sending a strong price signal when reserves are short, the strongest possible price signal, i.e., the penalty factor, should be used when reserves fall below the MRR. Relying on the possibility that the forecast error may be in PJM's favor to avoid an ex-post MRR shortage in order to price reserve quantities below the MRR, as suggested by the IMM, would dampen that strong price signal. In fact, under this premise, the price associated with a quantity of reserves equal to 0 MW would be less than the penalty factor, even though at that point PJM operators would be executing emergency operating procedures that are likely to have a cost greater than the penalty factor to create reserves.

16. In related arguments, Mr. Griffey, for the Load Coalition, contends that: i) PJM's approach is too conservative because not all probabilistic data points are positively correlated, and some may be negatively correlated; and ii) PJM is using a three-year average of forecast errors in load, wind, solar, net interchange and forced outage as a proxy for actual change in reserves. However, his criticism is inapt, because he misstates PJM's proposal. PJM is not proposing to use three year average of forecast errors as proxies for actual change in reserves. As I stated in my Initial Affidavit, at paragraph 15(c), PJM is proposing to combine error data and Regulation Requirement data point-by-point to derive a net-load error probabilistic distribution. This entails that the historical net-load error is calculated every 5 minutes for the Synchronized and Primary Reserve Requirement and every 15 minutes for the 30-minute Reserve requirement. This is apparent from the formula I showed in my initial affidavit, which is reproduced here:

Net Load Error at t = (Actual Load at t – Actual Wind Output at t – Actual Solar Output at t – Actual Net Interchange Schedule at t) – (Forecast Load for t at t-x – Forecast Wind Output for t at t-x – Forecast Solar Output for t at t-x – Forecast Net Interchange Schedule for t at t-x) + Forced Outages Thermal Units between t-x and t – Regulation Requirement at t.

The above formula represents the actual change in reserves between the time "t-x" and the time "t" adjusted for the regulation requirement. It is clear from the formula that no "proxies" are being used to calculate the actual change in reserves. It is also clear from the formula that any negative or positive correlation (or even no correlation) between the uncertainties are captured by the net-load error empirical distribution. For example, if between 8:30 a.m. and 9:00 a.m. wind was overforecasted but solar was underforecasted, this offsetting effect will be reflected in the net-load error calculation for 9:00 a.m.

17. The Load Coalition misreads my reference to the concept of "expected value" to contend that PJM is using averages to set prices, which they contend is inappropriate. This contention is unsupported and incorrect. Expected value is an appropriate concept to use when dealing with uncertain outcomes that depend on probabilities. As stated in my Initial Affidavit,[10] when procuring reserves above the MRR, there is both: (1) a probability that such reserves *will* be enough to avoid

[10] Rocha Garrido Initial Aff. ¶¶ 8-10.

an MRR deficiency, thus avoiding triggering the penalty factor; *and* (2) a probability that such reserves *will not* be enough to avoid an MRR deficiency, triggering the penalty factor. The calculation of the value of reserves above the MRR must consider the probabilities and outcomes under the two scenarios above. The concept of expected value provides a way to consider such probabilities and outcomes to establish the value of reserves, which result in the mathematical formula employed to derive the downward-sloping section of the ORDC proposed by PJM. Furthermore, this is consistent with the principles outlined by Hogan and Pope.[11] If the concept of expected value is not employed, the alternative would be to dismiss the probabilities altogether and determine a priori based on subjective judgment that an uncertainty will either occur or not occur. For example, if expected value is not used then the price associated with procuring 500 MW of reserves in excess of the MRR would either be the penalty factor (if the decision is to assume that the uncertainty would occur) or $0 (if the decision is to assume that the uncertainty would not occur). Treating uncertainties in this binary manner is plainly not appropriate.

18. Mr. Konidena on behalf of the Load Coalition argues that the ORDC width should be clipped both on the left and right because PJM is not properly accounting for all the contributing factors. This contention is based on a misinterpretation of my Initial Affidavit and the overall PJM proposal as well as a failure on Mr. Konidena's part to recognize the differences between operating reserves in real-time and capacity reserves to ensure long-term resource adequacy planning. First, Mr. Konidena wrongly characterizes PJM's curve as having its proposed width because renewable penetration is low, whereas I stated in my Initial Affidavit only that current renewable penetration is impactful for reserve procurement notwithstanding that renewable penetration is low relative to the total generation in PJM.[12] Nothing in that is inconsistent with even greater need for flexible resources as renewable penetration increases (as noted in the PJM statement quoted by Mr. Konidena).

Second, Mr. Konidena argues that "[r]enewables are getting penalized"[13] in my affidavit because (he alleges) I neglect the contribution of renewables to planning reserve requirements measured via the capacity credit concept. This line of reasoning reveals a lack of recognition of the difference between operating reserves in real time, which are procured via ORDCs to address real-time uncertainties, and capacity reserves, which are driven by planning reserve requirements and procured in PJM's capacity market to ensure long-term resource adequacy. The concept of capacity credit cited by Mr. Konidena is relevant to capacity resource adequacy but not to operating reserves. As he uses the term, "capacity credit" refers to the expected contribution of a renewable resource to meeting load at annual peak times. PJM uses that concept to determine the unforced capacity value that renewable

[11] Hogan & Pope Reply at 5-6.

[12] Rocha Garrido Initial Aff. ¶ 20(b)(ii).

[13] Affidavit of Rao Konidena on Behalf of the PJM Load/Customer Coalition ¶ 37 (Attachment E to the Protest of the PJM Load/Customer Coalition, Docket Nos. EL19-58-000, et al. (May 15, 2019)).

resources can offer for sale in PJM capacity auctions. Hence, for ORDC development, the capacity credit of renewables is irrelevant.

Third, Mr. Konidena argues that zonal considerations regarding renewable penetration and peak loads are overlooked in PJM's proposal. Again, this is incorrect. PJM's proposal considers the development of zonal ORDCs. The considerations he cites that pertain to those zonal ORDCs are addressed in my Initial Affidavit in paragraph 25. Moreover, Mr. Konidena raises these zonal considerations as a criticism to PJM's proposed Regional Transmission Organization ("RTO")-wide ORDCs, which is unwarranted given that the RTO-wide ORDCs are developed using RTO-wide real-time uncertainties data and such RTO-wide data is composed of zonal data.

Fourth, Mr. Konidena argues that PJM does not address the potential impact of increased behind-the-meter generation on the ORDCs. This is inaccurate. The proposed ORDCs are based on actual data (which will be regularly updated) and as such, an increase in behind-the-meter generation will be reflected in lower load values which would tend to decrease the magnitude of the historical load forecast error, in turn reducing the width of the ORDCs.

19. The IMM argues that PJM's proposed use of intermittent resource forecast error will yield very unreasonable results with the expected significant increase in wind/solar penetration. However, that conclusion is unsubstantiated and not based on analysis. It is not possible to know whether future wind and solar forecast errors under higher penetration levels will remain at the same percent levels as those seen today. But, assuming (as the IMM suggests) that such errors are to remain at those percent levels and also assuming the IMM's scaling calculations are correct, then the resulting ORDC would accurately reflect the real-time uncertainties of such potential future system. In other words, such ORDC would work as intended and reflect the reserve and price levels associated with such uncertainties.

20. The IMM argues that the PJM ORDC proposal has data issues on forced outages, intermittents, and load. PJM acknowledges that there is an error in the quantification of overlapping forced outages for the ORDCs used in the simulation results in the March 29, 2019 filing. To be clear, this error is not intrinsic to the proposed methodology, only to the illustrative application of the methodology included in the March 29 Filing. This error results in a slight overstatement of the amount of forced outages: the 30-minute forced outage values are overstated by an average of 6 MW for the 2015–2017 period while the 60-minute forced outage values are overstated by an average of 12 MW. Therefore, with the error corrected, PJM's simulation would show a corresponding slight reduction in the original estimated cost impact. The remaining minor errors cited by the IMM related to missing load, wind and solar data, and incorrect solar forecast data are inconsequential. The volume of missing and incorrect values (a few dozen for each ORDC) is insignificant when compared with the total data points used to develop each ORDC (more than 13,000). Last, the IMM statement that "[t]he forecast data and the forced outage data were not properly joined due to a mismatch in the

respective timestamps"[14] simply is not true. All of the data PJM used was in Eastern Prevailing Time (except for one hour each year at the transition to daylight savings time).

Arguments that PJM's Proposed ORDC Will Procure Excess Reserves

21. Some parties contend that PJM's proposed ORDCs will lead to procurement of unreasonably excess reserves, arguing that the curve is too wide, or that reserves beyond the MRR plus 190 MW should have zero value. These views, however, are mere assertions, reflecting judgments that there is no uncertainty in reserve levels beyond some arbitrary point, or that the value of reserves in reducing the uncertainty that does exist should simply be ignored. The parties making these assertions present no data or analysis to support their implicit view that there is no uncertainty, or that reserves' value in reducing uncertainty should be ignored.

22. By contrast, PJM's proposed ORDCs are based on quantified real-time uncertainties. Such uncertainties have historically reached large magnitudes as shown in Table 1 below. These observations drive the width of the ORDCs proposed by PJM, because large uncertainties present the possibility of falling below the MRR even at large levels of reserves above the MRR. The probabilities of such large uncertainties is low, but it is greater than zero probability. One *could* trim the ORDCs at a point other than when the probability of falling below the MRR is zero, but that would constitute a design choice to deem the probability of experiencing large magnitude net-load errors to be zero, notwithstanding historical data showing otherwise.

Table 1

YYMM DD	HHMI (t)	Season	TBlock	Load Forecast Error	Wind Forecast Error	Solar Forecast Error	Forced Outages	ReqReq	Net Load Error
170629	1520	Summer	5	470	-526.521	-34.122	1538.7	525	2044.343
170610	1645	Summer	5	779	-703.505	-10.331	955	525	1922.836

Arguments that PJM's Proposed ORDC Methodology Is Theoretically Flawed

23. Some parties contend that PJM's ORDC proposal has theoretical flaws. Mr. Wilson, for example, provides a theoretical critique of PJM's construction of the ORDC, and argues that if PJM properly applied the ORDC principles developed by Drs. Hogan and Pope, the value of reserves beyond the MRR would be $10/MWh.

[14] IMM Protest at 43.

24. Mr. Wilson's claims are not supported by quantitative analysis. In order to determine that the price associated with a quantity of reserves equal to the MRR is $10/MWh, an estimate of the "Security Minimum" as well as a probabilistic distribution for the net-load error are required (so that the probability of falling below the Security Minimum when the quantity of reserves is equal to the MRR can be calculated). But Mr. Wilson does not provide valid estimates of either of these values. He relies instead on a "rough" loss of load probability estimate of 0.001 based on his claim that "system operators have generally been comfortable with the MRR."[15] However, as PJM showed in its March 29 Filing, system operators have regularly procured additional reserves *in excess* of the MRR based on their ongoing assessments of uncertainty. Hence, it is incorrect to conclude that system operators have generally been comfortable with the MRR. Moreover, although there are differences, due to operational practices in the PJM system, between PJM's ORDC implementation and the theoretical ORDCs discussed by Drs. Hogan and Pope, none of those differences render the PJM proposal inconsistent with the principles discussed by Drs. Hogan and Pope.[16] In addition, Hogan and Pope confirm in their accompanying affidavit and report that Wilson is misapplying their principles to PJM.[17]

25. Similarly, Old Dominion Electric Cooperative ("ODEC") applies what they claim is the Hogan-Pope Value of Load Loss method to show that PJM ORDC values are "out-of-bounds,"[18] and that PJM's ORDC methodology is therefore flawed. ODEC's claim is incorrect. ODEC omits from the Hogan and Pope excerpt they quote an explicit extension of their method "to include minimum contingency reserves (*i.e.*, the Minimum Reserve Requirement)."[19] That extension is detailed in the Hogan and Pope appendix submitted in the March 29 Filing. Overlooking this permissible application of the Hogan and Pope principles, the formula employed by ODEC applies only when there is no MRR, but PJM's ORDC reasonably includes an MRR. Therefore, the conclusion drawn by ODEC regarding a probability of loss of load being "out-of-bounds" is premised on applying a formula that *does not* accommodate an MRR to a setting that properly *does* include an MRR.

[15] Affidavit of James F. Wilson in Support of the Protest of the Clean Energy Advocates ¶ 30 ("Wilson CEA Aff."). The Wilson CEA Aff. is attached to the Protest of Clean Energy Advocates, Docket Nos. EL19-58-000, et al. (May 15, 2019).

[16] Hogan & Pope Reply at 5-6.

[17] *Id.* at 9-10.

[18] Comments of Old Dominion Electric Cooperative on Reserve Price Formation Proposal, Docket Nos. EL19-58-000, et al., at 6 (May 15, 2019).

[19] Hogan & Pope PJM ORDC Report at 16 (Exhibit 1 to Attachment C to the March 29 Filing).

26. The correct interpretation of the PJM data ODEC cites is as follows:

PJM data: at 1,500 MWs of reserves (i.e., 100 MWs in excess of the MRR) the PJM ORDC value for the Summer 5 period is $438.90 per MWh.

Correct Interpretation (consistent with formula included in Hogan and Pope's appendix):

Penalty Factor x (PBMRR of 1,500 MW) = $438.9

PBMRR of 1,500 MW = $438.9 / $2,000 = 0.219 or 21.9%

There is a 21.9% chance that the level of reserves fall below 1,400 MW (the MRR) when procuring 1,500 MW (i.e., 100 MWs in excess of the MRR) of reserves. This probability corresponds to how often historically (i.e., the last three years) the total net load error has been greater than 100 MW during the Summer 5 period.

In short, PJM's ORDC results are not "out of bounds."

27. For its part, the IMM argues that PJM's proposed ORDC is "unprecedented"[20] when compared to other RTOs and Independent System Operators ("ISO"). PJM's proposed ORCDs are is based on the magnitude of PJM's real-time uncertainties. A comparison of approximate average real-time uncertainties between PJM and five other ISOs is presented in Table 2 below. That table shows approximate average 30-minute load forecast error, wind forecast error, solar forecast error, and thermal forced outages for PJM during peak time. The same PJM percent error levels are then applied to load, wind, and solar data from five other ISOs also during peak time.[21] To get a sense of the "total average error," the sum of the four 30-minute error quantities is shown in the Total column. PJM's Total Average Error is among the highest of this group. The only RTOs with comparable figures differ from PJM, however, in that they have ramping products, while PJM does not. PJM is therefore the only ISO or RTO with that level of forecast error relative to its MRR that does not have a market means to mitigate that concern.

[20] IMM Protest at 26.

[21] Load, wind, and solar data for PJM and the other are five ISOs are from the 2018 North American Electric Reliability Corporation Long-Term Reliability Assessment ("2018 NERC LTRA") available at: *2018 Long-Term Reliability Assessment*, North American Electric Reliability Corporation (Dec. 2018), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf.

Table 2

	2019 Total Internal Demand (Load) (MW)	2019 Solar at Peak (MW)	2019 Wind at Peak (MW)
PJM	152479	1376	1327
MISO	125284	240	2491
SPP	52695	197	1359
NE	25511	66	189
NY	32857	27	369
CAISO	55109	9265	1053

	Load Forecast Error (MW)	Forced Outages (MW)	Solar Forecast Error (MW)	Wind Forecast Error (MW)			
	0.04% of Load	**0.09% of Load**	**2.00% of Solar**	**5.50% of Wind**	**Total Error**	**MRR**	**Total Error as % of MRR**
PJM	61.0	137.2	27.5	73.0	298.7	1500	19.9%
MISO	50.1	112.8	4.8	137.0	304.7	1500	20.3%
SPP	21.1	47.4	3.9	74.7	147.2	1500	9.8%
NE	10.2	23.0	1.3	10.4	44.9	1500	3.0%
NY	13.1	29.6	0.5	20.3	63.5	1500	4.2%
CAISO[22]	22.0	49.6	185.3	57.9	314.9	1500	21.0%

Challenges to PJM's Proposed "Look-Ahead" Period

28. To measure forecast uncertainty, PJM proposed a 30-minute look-ahead period for 10-minute reserves. The IMM and ODEC object that this look-ahead period is too long, and should instead be 15 or 20 minutes. Contrary to these objections, PJM's proposed look-ahead period is reasonable.

29. In my Initial Affidavit, at paragraph 13, I explained that for "the Synchronized and Primary Reserve Requirement, the length of the interval between the solution of the

[22] In the 2018 NERC LTRA, the reporting is made for the California-Mexico Reliability Region, not at the CAISO level.

RT SCED case and the end of the period in which the procured reserves are expected to respond in case they are deployed is at least 20 minutes: (T+10) – (T-10)." PJM proposes using a 30-minute look-ahead period because the additional 10 minutes are "intended to capture deviations from when the RT SCED case is run (it may not be exactly run at T-10) and also to capture the value of reserves in subsequent intervals."[23] When RT SCED cases are run earlier than 10 minutes prior to the target time, the forecast inputs into such RT SCED cases are from 15 minutes or even 20 minutes prior to the target time. This occurs because forecast models must be run before RT SCED cases (and the forecast models are run only every 5 minutes). In other words, the inputs used in some RT SCED cases targeted for a time T are from T-15 or even T-20. Coupled with the fact that the procured reserves are expected to respond between T and T+10, this produces a look-ahead period of 25 minutes ((T+10) – (T-15)) or even 30 minutes ((T+10) – (T-20)) for some RT SCED cases. The ODEC and IMM proposals for only a 15 or 20-minute look-ahead period therefore would not capture the elapsed time in all cases between the RT SCED run and the deadline for the scheduled reserves' response.

30. To further illustrate how PJM's proposed 30-minute look-ahead is reasonable, consider the following example of an ORDC that (unlike PJM's proposal) is based on a 15-minute look-ahead as proposed by the IMM. Assume that at 8:50 a.m. an RT SCED case is run for a target time of 9:00 a.m. Further assume that the inputs that were used in the case were from forecasts run at 8:46 a.m.' (14 minutes prior to the target time). Then assume that under an ORDC developed (per the IMM) with only 15-minute load uncertainty data and an MRR of 1,500 MW, the procurement of reserves resulted in 2,000 MW of reserves at $0/MWh. In other words, the procurement occurs at the end of the 15-minute ORDC, indicating that the probability of 15-minute load forecast error greater than 500 MW is zero). The procured 2,000 MW of reserves will be ready to be deployed between 9:00 a.m. and 9:10 a.m. If at 9:00 a.m., once the load uncertainty is realized, the total load forecast error is 490 MW, 490 MW of the reserves will need to be converted into energy, leaving 1,510 MW of reserves available to respond between 9:00 a.m. and 9:10 a.m. If at 9:04, an increase of load were to occur that is greater than 10 MW, the system would be left with reserves below the 1,500 MW MRR. However, the probability of such an event was not incorporated in the development of the ORDC because the uncertainty was restricted to 15 minutes (and 9:04 a.m. is 18 minutes from when the forecasts that served as inputs to the RT SCED cases were run). This specific example is meant to convey the important point that the uncertainty of net-load error during the contingency response period (9:00 a.m.–9:10 a.m. in the example above) cannot be disregarded when developing the ORDCs. The ORDCs in the PJM proposal use 30 minutes to account for the SCED forecast interval, the contingency response period, and value of reserves in subsequent period as stated in the original filing. The IMM and ODEC alternative proposals overlook this important consideration, and thus would not address the actual uncertainty that the system could fall below the MRR.

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[23] Rocha Garrido Initial Aff. ¶ 13.

31. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket No. ER19-1486-000**
	)	
PJM Interconnection, L.L.C.	)	**Docket No. EL19-58-000**

VERIFICATION OF DR. PATRICIO ROCHA GARRIDO

Dr. Patricio Rocha Garrido, being first duly sworn, deposes and states that he is the Dr. Patricio Rocha Garrido referred to in the foregoing document entitled "Reply Affidavit of Dr. Patricio Rocha Garrido," that he has read the same and is familiar with the contents thereof, and that the testimony set forth therein is true and correct to the best of his knowledge, information, and belief.

DR. PATRICIO ROCHA GARRIDO

Subscribed and sworn to before me, the undersigned notary public, this 21st day of June 2019.

Linda Spreeman

Notary Public

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

Attachment E

Rewarding Flexibility: An Analysis of the Impact of PJM's Proposed Price Formation Reform on the Incentives for Increasing Generator Flexibility

Rewarding Flexibility: An Analysis of the Impact of PJM's Proposed Price Formation Reform on the Incentives for Increasing Generator Flexibility

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June 7, 2019

Executive Summary

Many trends in current power systems are increasing the importance of maintaining and increasing flexibility. Such trends include increasing generation from wind and solar energy, whose variability may be poorly correlated with electricity demand changes, increasing shares of self-scheduled generation, and volatile power flow changes at the borders of RTOs driven by small price differences. There are multiple types of flexibility that can be enhanced from a dispatchable thermal generator, including a higher maximum power output, a lower minimum power output, a faster startup time with a consequent reduction in startup cost, a faster ramp rate for changing the power output level while online, or combinations of these. However, many of these features reduce the costs to the system and to the consumer by shifting the more flexible generator to provide less energy or to be online for fewer hours, reducing energy revenue.

An increased incentive for generators to invest in and offer flexibility was one of several motivations for a recent proposal by PJM to reform its reserve market pricing formation. The PJM proposal consisted of increasing the amount of both synchronized (spinning) and offline (non-spinning) operating reserves, and to increase the prices paid to generators for reserves as well as for energy. The main elements of the proposal intended to achieve this impact are new Operating Reserve Demand Curves (ORDCs) with 20-40 gradually decreasing levels of penalties in place of the 2-step curves currently in use, an increase of the magnitude of the penalties for reserve shortages, and the introduction of a new 30-minute Secondary Reserve product.

This report examines the proposed changes to the ORDCs and the addition of the 30-minute reserves, and assesses the relative impacts of these changes on the financial incentives for natural gas combined cycle generators to invest in technology to increase the flexibility of their plants. The analysis simulates the Electricity Reliability Council of Texas (ERCOT) for the year 2016, superimposing either the current PJM ORDCs or the proposed ORDCs, and calculates the system costs, net revenues to each generator, and other metrics. The simulations are then repeated where one combined cycle generator receives a hypothetical upgrade to increase its flexibility. The change in net revenues to the owner of the upgraded generator offers a way to quantify the (dis)incentive to invest in flexibility. The comparison of this metric between the two reserve market designs provides a way to assess whether the proposed reserve market design improves or weakens the incentive for flexibility.

The results of the analysis strongly suggest that the proposed changes to the reserve market by PJM would in fact increase the incentives to invest in most types of flexibility. Upgrades to increase the maximum output, decrease the minimum output, increase the ramp limit, and combinations of all features would lead to a greater increase in net revenues (a proxy for generator profit) under the proposed design, as compared with current reserves. Only the incentive to invest in a faster startup time in is not improved by the proposed market change.

Table ES.1: Change (due to Reserve Design) in the Change (due to flexibility upgrade) of Annual Net Revenues to Owner ($M)

	All Features	Lower Pmin	Higher Pmax	Faster Start	Faster Ramp
G35	4.3	1.5	2.2	0.0	2.4
G37	-0.2	0.4	2.2	-0.9	0.7
G50	3.2	2.2	1.6	0.5	-1.9

1. Background

Generator Flexibility

The recent and projected future increases in the share of variable renewable generation has been driving increased concern about the need for flexibility in the electric power system. Specifically, the combined effects of variability in demand, solar generation, and wind generation require that the dispatchable generation resources be constantly adjusted to maintain the demand-supply balance. Additional sources of stress on dispatchable generation resources include self-scheduled resources, for example cogeneration, and rapidly changing flows of power across the seams between RTOs driven by small price differences. To the extent that generation resources have wider operating ranges (higher maximum and/or lower minimum output limits), can ramp more quickly, or can startup more quickly and/or at lower cost, these resources can make it easier for the system to maintain balance between dispatchable supply and the net load.

Many previous studies have explored aspects of the value of increased flexibility from a variety of resource types, including renewables, storage, transmission, demand response, and more flexible thermal generators. In particular, there exist currently technological improvements via operational and physical changes that would enable natural gas combustion turbines, both simple cycle and combined cycle units, to operate at a lower minimum output, to operate at a higher maximum output, to ramp more quickly up or down while online, to start up more quickly from an offline state with corresponding lower startup costs, or any combination of the above. Any enhancement to the operating parameters will require investment by the unit owner and will require targeted R&D investments on the part of turbine manufacturers.

The potential barrier to many of these technologically feasible upgrades is that the generation resource owner will not make additional investments to enable flexibility, and subsequently offer this flexibility to the market, unless the change will improve the financial position of the resource. Some of the flexibility that can lower cost and improve the reliability of the system would entail shifting the use of the now more flexible resource to provide less energy and instead provide greater reserve capability. Unless the net revenue from the increased reserves and other ancillary services provision is greater than the reduction in energy revenues, the generator owner has no incentive to make such investments.

PJM’s Reserve Market and Proposed Design Changes

Starting in 2017, and continuing up through early 2019, PJM developed a set of proposed reforms to their reserve market design and price formation to address shortcomings in the current design. The three main features that PJM has identified as problematic are:

- Synchronized reserves are separated into two products, Tier 1 and Tier 2, that face different rules and different compensation;
- The magnitude of penalties and the shape of the current operating reserve demand curve (ORDC) does not sufficiently encourage performance by resources providing reserves;
- There is misalignment of reserve products between the day-ahead and real-time markets that leads to insufficient procurement of reserves in advance.

The motivations for PJM to modify the reserve market design include providing transparency, maintaining reliability, providing incentives to follow commitment and dispatch instructions, and incentives to make continuing efficient investments. In particular, the latter motivation includes specifically an expressed desire in PJM documents to incentivize an increase in flexibility on the part of generation resources, recognizing the growing need for this flexibility to maintain reliability and simultaneously keep consumer costs low.

A series of stakeholder meetings in late 2018 and early 2019 failed to produce a positive vote to adopt the proposed reforms within the stakeholder voting rules for PJM. PJM subsequently submitted a filing to the Federal Energy Regulatory Commission (FERC) on March 29, 2019, arguing that current reserve market rules are unjust and unreasonable, and requesting that FERC order the new rules be adopted.

At the time of writing of this report, this filing remains open for public comment.

Objective of this Analysis

In this analysis, I examine one aspect of the proposed reforms in PJMs filing to FERC, and its impact on one of the criteria identified as a motivation. Specifically, I analyze the proposed changes to the ORDCs from the current curves used to the proposed new curves. The main objective of the analysis is to evaluate the assertion by PJM that the revised ORDCs would improve the incentive for flexible investments and operations by generators.

To perform this assessment, I adapt a modeling framework developed in collaboration with General Electric to quantify the economic value of several hypothetical flexibility enhancements that could be made to existing natural gas combustion turbines within combined cycle units. The model simulates a power system before and after each type of flexibility enhancement and calculates the net change in total system costs and the change in net revenue to the generation owner due to the upgrade. To explore the PJM proposal, I perform the analysis twice, once for the current ORDCs and a second time using the proposed ORDCs. The difference between the change in net revenue from the upgrade under the current ORDCs and the change under the proposed ORDCs provides an illustrative measure of the relative change in the incentive to invest in generator flexibility.

2. Methodology and Assumptions

Unit Commitment Model

The computational model used in this analysis is a deterministic unit commitment (UC) model. The UC model solves for the minimum cost schedule of commitment status and power output from all dispatchable generators subject to balancing supply and demand at every time period and the operational constraints of the generators. The UC model is used to determine which generators are online and which are offline for each hour of the simulation time horizon; when a generator is online, its power output must be between its minimum and maximum output levels; for some technology types, the minimum power output is significantly above zero.

The model minimizes the total variable cost over the entire time horizon, which includes the fuel cost of generation, the non-fuel variable operations and maintenance (O&M) cost of generation, and the costs of starting up generators when they transition from offline to online. In addition, the objective function that is minimized includes several penalty factors to ensure realistic solutions, including a penalty if demand is not completely satisfied in any given hour and a penalty if any renewable energy is curtailed. None of the results shown in this report contain any non-served demand or curtailed renewables. Finally, the ORDCs in this analysis are implemented also using a penalty in the objective function, defined by ORDC for the total procured reserves in each hour. This is described in more detail below.

The model minimizes the total cost while enforcing a number of system constraints, including:

- Demand is satisfied in all hours;
- Required reserves of each type are procured in each hour up to the point where the penalty from the ORDC exceeds the marginal cost of acquiring one more MW of reserve from a generator;
- Generators are either online or offline in each hour;
- Output from online generators are between their minimum and maximum output
- Changes in the power output between consecutive hours may not exceed the maximum ramp limit for that unit;
- If a unit is started up, it must remain online for a minimum number of hours;
- If a unit is shutdown, it must remain offline for a minimum number of hours;
- When a unit is started up, there is a delay before the unit becomes available to dispatch, and during these times it follows a prescribed power profile. The time lag, power profile during the startup ramp, and the startup costs all depend on the elapsed time since the generator last shutdown (i.e., its temperature).

The UC model used is implemented as a mixed integer linear program, using the GAMS software system, and solved using CPLEX 12. The detailed mathematical formulation and numerical parameter assumptions are provided in the technical appendix, and all code and data files are publicly available in a GitHib archive (http://github.com/mortpsu/PJMFlexibilityStudy).

The model used is the same fundamental approach as the software used to clear PJM's day-ahead market and those of other RTOs. The primary differences between the simulation here and actual markets are the absence of transmission grid detail that RTOs use to enforce security constraints, and the use of assumed cost parameters (described below and in the appendix in detail) rather than market bids. There is also no treatment in the simulation of load or renewable forecast uncertainty. Therefore, there is no equivalent in the simulations here of a real-time market, in which generator outputs are modified to adapt to revised load forecasts. Because there is no treatment of uncertainty in this analysis, the results most likely understate the value of the flexibility, which would increase in the presence of forecast uncertainty and subsequent adjustments to the dispatch.

ERCOT Simulation

In an effort to provide timely information about PJM's proposed reserve market reform, I have adapted a pre-existing model of the Electric Reliability Council of Texas (ERCOT), the power system that covers the majority of Texas. The data to model the PJM grid with the precision necessary to be informative was not available within the desired time frame. Nevertheless, the analysis in this report using the simulation of ERCOT with the addition of the PJM ORDCs provides qualitative and illustrative insights into the impact of the proposed reform on the incentives to increase flexibility. Here we provide high-level description of the assumptions used for the ERCOT representation; more details can be found in the technical appendix and the online archive.

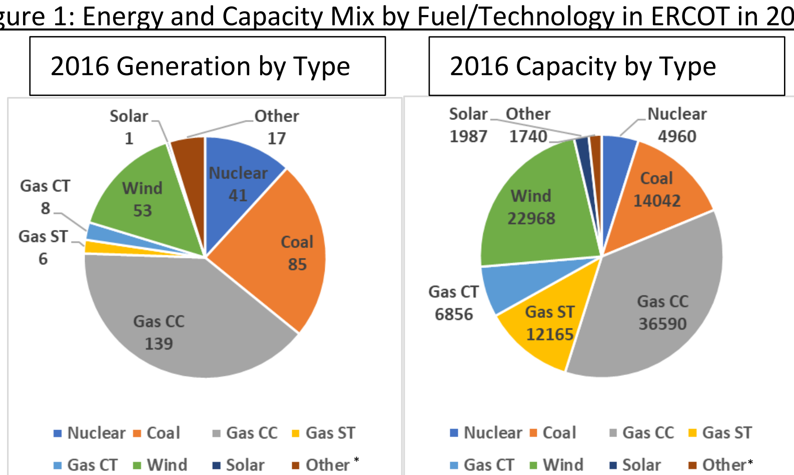
The analysis presented in this report is based on a simulation of ERCOT for the year 2016. The data and assumptions specific to ERCOT include the generator characteristics, the hourly pattern of demand, wind generation, and solar generation, and the historically observed real-time energy locational marginal prices (LMPs). The primary sources for the data are ERCOT's website, the U.S. EPA's eGRID database, and S&P Global Insight's SNL Energy commercial database.

The relative shares of capacity and of energy in 2016 are shown in Table 1 and Figure 1. The largest share of energy is from natural gas combined cycle generation, followed by coal steam and then wind generation. ERCOT has two operating nuclear plants for a total capacity of just under 5000 MW. ERCOT also retains a fair amount of older natural gas steam turbine units, which are largely used for load-following and peaking. Roughly one third of the natural gas combined cycle and natural gas combustion turbine (simple cycle) are co-generation units; the majority of these are self-scheduled and do not fully participate in the competitive energy market. The "Other" category in Table 1 and Figure 1 is an aggregate of internal combustion units (mostly diesel or natural gas), biomass, hydro, waste-steam, and other less common fuels and technologies.

Table 1: Energy and Capacity by Fuel/Technology in ERCOT in 2016

	Generation (millions of MWh)	Summer Capacity (MW)
Nuclear	41	4960
Coal	85	14042
Gas CC	139	36590
Gas ST	6	12165
Gas CT	8	6856
Wind	53	22968
Solar	1	1987
Other	17	1740

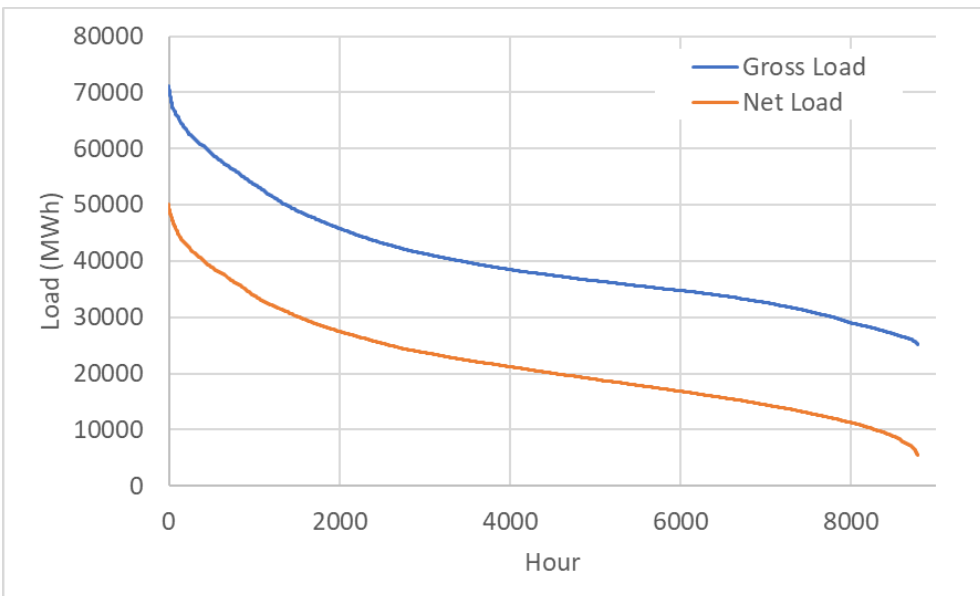
Figure 1: Energy and Capacity Mix by Fuel/Technology in ERCOT in 2016



*Other Includes: Internal Combustion/Diesel, Biomass, Hydro, Waste Steam, and other fuels.

The hourly load, wind, and solar generation in ERCOT in 2016 are available at ERCOT's website. The load duration curve for 2016 ERCOT native gross load is shown in Figure 2 below. Because the objective of the analysis here is to quantify the economic impacts of changes to the reserve markets and technology changes to generators that enhance their flexibility, the modeling approach focuses on representing the dispatchable portion of the ERCOT energy market, rather than explicitly modeling all generators. Specifically, the goal is to simulate the generators that participate in the ERCOT market and respond to ERCOT dispatch instructions. The model is therefore designed to meet the hourly net load, which is defined as the load minus the sum of nuclear generation, wind generation, solar generation, co-generation (non-dispatchable), and other non-dispatchable resources. The resulting net load is also shown in Figure 2; note that the load duration curves for the gross and net load do not necessarily occur in the same hours. In the model, the historically observed hourly net load in chronological order defines the demand in each hour.

Figure 2: Load Duration Curves for ERCOT Gross and Net Load in 2016



PJM Reserve Market Representation

To explore the impact of changes to the ORDCs for PJM, each set of ORDCs (current and proposed) are represented within the ERCOT simulation model. The current PJM ORDCs consist of one curve for 10-minute synchronized reserves for all hours of the year, and a second curve for 10-minute primary reserves for all hours. The synchronized reserve target can only be procured from online (spinning) resources, while the primary reserves met by the sum of spinning and non-spinning (offline quick-start) reserve capacity. Both curves have only two steps with penalties defined as:

Synchronized Reserve ORDC:

0– 1450 MW	\$850 / MW
1450–1640 MW	\$300 / MW
> 1640 MW	No penalty

Primary Reserve ORDC:

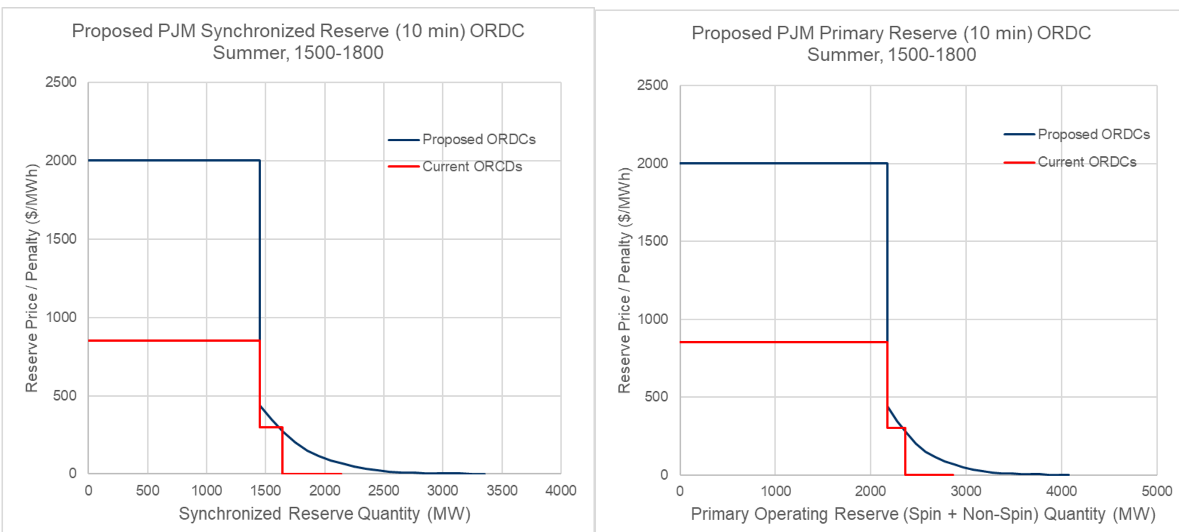
0– 2175 MW	$850 / MW
2175–2365 MW	$300 / MW
> 2365 MW	No penalty

The current ORDC curves are shown in Figure 3 below.

The proposed ORDCs are described elsewhere by PJM. In their proposal, PJM has defined six curves for each season, each for a four-hour period of the day, resulting in 24 curves for each reserve type. As an example, the proposed curves for summer hours 1500-1800 are shown below in Figure 3, along with the current PJM ORDCs, for both 10-minute Synchronized and 10-minute Primary reserves.

In addition to the Synchronized and Primary Reserves, the PJM proposal would add a third category, Secondary Reserves, which are a 30-minute product, and can be provided from either spinning or non-spinning reserves that can be delivered within 30 minutes.

Figure 3: Proposed and Current ORDCs for 10-minute Synchronized and 10-minute Primary Reserves (Summer 1500-1800).



The penalty from the ORDC is not necessarily the actual price of the reserve product. The solution of the unit commitment model includes the shadow prices of each constraint, which represents the marginal cost of meeting that constraint. The shadow prices on the reserve requirements of each category are the basis for the compensation for providing reserves. In the case of the proposed reserve market, there are three prices:

- Price of 10-minute Synchronized Reserves
- Price of 10-minute Primary Reserves
- Price of 30-minute Secondary Reserves

The cleared reserves from any given generator, however, consist of four types: 10-minute spinning (from online units), 10-minute non-spinning (from offline units that can start within 10 minutes), 30-minute spinning (from online units), and 30-minute non-spinning (from offline units that can start in less than 30 minutes).

The rules for determining payments to generators are as follows

1) For an online unit providing 10-minute spinning reserves, the unit receives the sum of all three prices (10-minute Synchronized Reserve Price, the 10-minute Primary Reserve Price, 30-minute Secondary reserve Price) for each MW of 10-minute reserve provided;
2) For an offline quick-start unit, the unit can receive the sum of the 10-minute Primary Reserve Price and the 30-minute Secondary Reserve Price for each MW of 10-minute non-spinning reserve provided;
3) For an online unit that provides 30-minute spinning reserves, the difference between the 10-minute and 30-minute reserves is paid at the Secondary Reserve Price;
4) For an offline quick-start unit that provides 30-minute non-spinning reserves, the difference between the 10-minute and 30-minute reserves is paid at the Secondary Reserve Price.

The analysis here does not distinguish between Tier 1 and Tier 2 reserve categories, and for simplicity treats all synchronized reserves consistently. No bidding by generators for reserves is assumed, and the prices paid are solely determined by the shadow prices in the model solution.

Experimental Design

The simulation of ERCOT is performed for every day of 2016, with the exception of Jan 1, Dec 30, and Dec 31 (to account for boundary conditions). The simulation for each day is repeated for different ORDC cases and different flexibility upgrade cases. For any given natural gas combined cycle generator in ERCOT that is identified as a potential candidate for upgrades, 12 simulations of each day are performed. The two ORDC cases are the current PJM ORDCs and the proposed ORDCs, as described above. For each ORDC case, a base case is simulated, assuming characteristics for all generators that approximate the historically observed generation patterns. In addition, five hypothetical upgrade cases are simulated in which the characteristics of the candidate generator are modified as follows:

- "Pmin": The minimum output of the generator is 15% lower than its previous minimum
- "Pmax": The maximum output of the generator is 20% higher than its previous maximum
- "Start": The startup time (from offline to at or above minimum output and available for dispatch) is reduced by as much as half and the startup cost is reduced by 75%
- "Ramp": The ramp limit of the generator is double its previous ramp limit
- "All": All four of the above modifications are made simultaneously.

The key results of each set of simulations for one candidate generator consist of the system savings, defined as the difference in total cost between the base case and one of the flexibility cases, and the change in net revenue to the upgraded generator. The net revenue in each case is calculated as the revenues (energy plus reserves) minus the costs (generation fuel costs, variable non-fuel O&M costs, and startup costs). The difference in net revenue between the base case and an upgrade case provides a measure of the incremental financial benefit to the owner of the increased flexibility. These quantities are calculated under the current PJM ORDCs and again under the proposed PJM ORDCs; the difference between the change in net revenue then provides a measure of the relative incentive to the generator owner to adopt the flexibility under each reserve market design.

The analysis presented below consists of the complete set of simulations for three candidate combined cycle generators in ERCOT, summarized in Table 2. We do not identify the actual plants in ERCOT and will refer to them using their ID within the model. These three units are chosen because they represent different dispatch patterns. G37 is a unit that runs more as a baseload unit, with the largest number of fired hours per year and the fewest starts per year from among these three. G35 is a mid-range unit that cycles frequently but not every day and has fewer fired hours than G37. G50 is at the lower end of the merit order among the combined cycle plants, and it cycles every day, and sometimes twice a day, with the fewest fired hours, the least energy provided, and the largest number of starts per year over 2016 from among these three.

Table 2: Candidate Generators for Hypothetical Flexibility Upgrade

Generator ID	TYPE	Capacity	Avg Heat Rate	CF	Hours Fired	# of Starts
G35	3x1 NGCC	650	7400	0.47	5680	249
G37	2x1 NGCC	520	7200	0.76	7884	28
G50	2x1 NGCC	550	7150	0.35	4243	400

3. Results of the Analysis

Comparison of ORDC Impacts for Base Case (No Upgrades)

Before presenting the impacts of flexibility upgrades on individual generators, the simulated prices and cleared quantities for reserves are summarized for the Base case (all generators assumed to have current operating parameters). Table 3 summarizes the hourly prices for energy and for the three reserve products in terms of percentiles of all hours in the 2016 simulations. The energy prices are only slightly higher under the proposed ORDCs. However, the 10-minute Synchronized and 10-minute Primary reserve prices are significantly higher. Under the current ORDC, the simulated 10-minute reserve prices are zero more than 50% of the time (similar to historical prices in PJM). In contrast, the 10-minute prices under the proposed ORDCs have a much higher probability of being non-zero, and a correspondingly higher probability of higher values. For example, only 2% of the hours have prices above $10/MWh for 10-minute Synchronized under the current ORDCs but 6% of the hours have prices above $10/MWh under the proposed ORDCs.

The cleared quantities of all reserve products (10-minute spinning and 10-minute non-spinning for both market designs, and 30-minute spinning and 30-minute non-spinning for the proposed design), are shown in Table 4. The proposed ORDCs clear higher amounts of 10-minute spinning reserves than the current ORDCs for almost every hour of the year, and slightly higher but comparable amounts of 10-minute non-spinning reserves for most hours of the year. In addition, the proposed design would clear significant quantities of 30-minute spinning reserves.

Table 3: Prices under Current and Proposed ORDCs for Base Case Simulations

	Energy Price		10-min Synch		10-min Primary		30-min Secondary
Percentile	Current	Proposed	Current	Proposed	Current	Proposed	Proposed
0.05	9.55	9.66	0.00	0.15	0.00	0.00	0.00
0.25	15.37	15.58	0.00	0.92	0.00	0.46	0.00
0.50	18.26	18.53	0.00	2.44	0.00	2.14	0.00
0.75	22.11	22.44	0.96	4.73	1.80	4.73	0.92
0.95	35.03	35.56	5.29	12.37	6.35	13.43	9.16
0.99	99.16	100.79	14.50	32.67	12.53	31.60	33.42

Table 4: Cleared Quantities of Reserves under Current and Proposed ORDCs for Base Case Simulations

	10-min Spinning		10-min Non-Spin		30-min Spin	30-min Non-Spin
Percentile	Current	Proposed	Current	Proposed	Proposed	Proposed
0.05	1640	2484	396	401	2393	401
0.25	1640	2750	561	559	3296	559
0.50	1665	2867	709	703	4336	703
0.75	1806	2981	929	950	4806	950
0.95	1969	3159	1393	1376	5227	1376
0.99	2050	3304	1614	1662	5454	1662

Annual Aggregate Impacts of Flexibility Upgrades

The 2016 ERCOT simulations were performed for the three candidate combined cycle units as described in the previous section, and the total system cost and net revenues to the candidate unit were determined for each of the ORDC/Flexibility combinations. The difference between the total system cost for each day between each flexibility upgrade case and the base case (for the same ORDC assumptions) were calculated for each day and summed over all days. The resulting cumulative change in total costs are given in Table 5, in Millions of $. This savings quantifies the reduction in the total variable costs to meet the load and reserve requirements over the simulated year due to the increased flexibility of the generator (all other generators remain unchanged). The reduction in costs is a useful proxy for the reduction in the cost of electricity costs, since the generation costs would be paid by the distribution utilities, and then reflected in the rates that consumers pay.

The pattern of savings under the current ORDCs and reserve market design are similar across the three candidate generators. The greatest savings would result from an increase in flexibility for all the characteristics at the same time: lower Pmin, higher Pmax, faster/cheaper startup, and faster ramp. After that, the next greatest savings occurs from an increase in the maximum output. The other three types of flexibility result in savings of a similar magnitude.

The relative savings by type of flexibility also follows the same trend under the proposed ORDC and reserve market design. However, an upgrade undertaken if the new reserve market were in place would lead to significantly greater savings, from a 60% increase to a doubling of savings from the very same technological modification. This provides suggestive evidence that flexibility will be more valuable to the system and to the consumer under the proposed reserve market design.

Table 5: Annual System Savings from Flexibility Upgrade ($ Million)

	Reserve Market	All Features	Lower Pmin	Higher Pmax	Faster Start	Faster Ramp
G35	Current	$15 M	$5 M	$7 M	$4 M	$4 M
	Proposed	$26 M	$8 M	$14 M	$10 M	$10 M
G37	Current	$12 M	$4 M	$7 M	$2 M	$3 M
	Proposed	$24 M	$8 M	$13 M	$7 M	$10 M
G50	Current	$15 M	$4 M	$8 M	$4 M	$3 M
	Proposed	$23 M	$8 M	$13 M	$9 M	$9 M

In a competitive market, whether PJM, ERCOT, or any other, a generator owner is less concerned with system savings than with the financial returns on their asset. Therefore, a critical outcome is the relative change in the net revenue to that unit from the upgrade. Table 6 shows the change in the cumulative annual net revenue to the upgraded generator in millions of $, calculated as the difference between the net revenue after the upgrade minus the net revenue before the upgrade (for the same ORDC case). Under the current ORDC and reserve market design, the greatest increase in net revenue would come from upgrading all the flexibility features at the same time, and the second greatest would be the faster startup only upgrade. For some of the plants, an upgrade to lower the minimum output or to have a faster ramp rate would actually lead to lower net revenues. Thus, under the current PJ ORDCs, there is a financial disincentive for owners to adopt these upgrades, even though the system cost would be lower.

The relative pattern of net revenue changes from upgrades remains the same under the proposed ORDCs, but in almost all cases, the increase in net revenue is larger under the proposed ORDCs relative to the current curves. The upgrades that under the current ORDCs would have resulted in a decrease in net revenue would result in a modest but positive increase in net revenue under the proposed ORDCs. Only in the case of G50 with the ramp rate only upgrade would net revenues decrease more under the proposed ORDCs.

In general, the pattern of results indicates that the gains to the generator owner of increasing the flexibility of their plant would be greater under the proposed reserve market design. In a system with greater procurement of reserves by the system, higher reserve prices, and higher energy prices, the incentives for investing in flexibility are substantially greater.

Table 6: Change in Annual Net Revenue to Generator Owner from Flexibility Upgrade ($ Million)

	Reserve Market	All Features	Lower Pmin	Higher Pmax	Faster Start	Faster Ramp
G35	Current	5.1	-0.5	0.3	3.9	-1.6
	Proposed	9.4	1.0	2.5	3.9	0.9
	Difference	4.3	1.5	2.2	0.0	2.4
G37	Current	7.2	0.5	0.4	4.5	0.0
	Proposed	6.9	0.9	2.5	3.6	0.7
	Difference	-0.2	0.4	2.2	-0.9	0.7
G50	Current	4.0	-1.3	0.2	2.3	0.0
	Proposed	7.2	0.9	1.8	2.7	-1.9
	Difference	3.2	2.2	1.6	0.5	-1.9

An alternative calculation provides another way to assess to the impact of the reserve market design on incentives for flexibility. Whereas the results above compared the net revenues before and after an upgrade for the same reserve market, we can also compare the net revenues for the same plant and same technological characteristics between the current and the proposed ORDCs, as shown in Table 7. For example, for G35 as operated today (no upgrade), just the change in the ORDCs would increase the annual net revenue to the owner by $1.5M. However, the version of G35 with higher max output, lower min output, faster startup, and faster ramp would increase its net revenue by $4.7M from the reserve market change alone. In other words, the more flexible version of the generator gains much more from the market change than the original less flexible version. The pattern of greater gains from the market change for more flexible versions is generally consistent.

The one type of flexibility that would not gain from the reserve market change are units that only have faster startup capability. The modified reserve price formation and reserve targets does not appear to improve the incentives for decreasing the startup time for generators. If this greater fast start capability is needed to improve reliability or reduce costs to a system, some alternative ancillary market or incentive would need to be developed.

Overall, the pattern of findings from examining several different candidate plants, several different flexibility upgrades, and comparing the financial impacts on the generator provide evidence that PJM's proposed reserve market and ORDCs would increase the incentive for investments in flexibility.

Table 7: Change in Annual Net Revenue to Generator Owner from Reserve Market Change ($ Million)

	Current Unit	All Features	Lower Pmin	Higher Pmax	Faster Start	Faster Ramp
G35	1.5	4.7	2.9	3.5	1.5	3.6
G37	3.5	2.6	3.8	5.2	2.2	4.2
G50	0.4	3.1	2.6	1.5	0.7	-1.4

Examples of Individual Days

To provide additional insight into the annual aggregate results presented in the previous section, we present the detailed results from two examples of one specific day and one specific upgrade to one of the generators.

Example #1: June 8, 2016, G35, Upgrade All Features

As a first example, this section shows the detailed results from June 8, 2016. This day is a representative example of a summer day. The load and net load are high but are not extreme peak episodes. The load, wind generation, and net load for this day are all roughly the 80th percentile for 2016. However, the pattern of renewable generation causes the net load to peak earlier than the actual load; the load and net load for this day are shown in Figure 4.

To establish the reference point before examining the impact of the upgrade, Figure 5 shows the impacts of the reserve market change on the base case (no flexibility upgrade) in terms of prices. In the upper left, the real-time LMPs over the simulated day are shown for both ORDC cases, which have minimal differences. Under the current PJM ORDCs, there is a shortage of spinning reserves at 1500, due to insufficient online resources, causing a price spike of $300 from the penalty. At most other times, the higher demand for spinning and primary 10-minute reserves under the proposed ORDCs results in higher prices, and the additional demand for 30-minute resources provides additional potential reserve revenue.

The change in net revenues to the owner of G35 due to the upgrade for the one day are shown in Table 8 for both ORDC cases and for every upgrade case. If G35 has upgraded all the flexibility features, the net revenue would increase by $18K under current ORDCs and by $40K under the proposed ORDCs, more than a doubling. The incremental gain to the owner from the upgrade is roughly doubled by the change in the ORDCs. If the owner had already made the upgrade to the more flexible version, the change in market rules would have increased the net revenue, but the original, less flexible current unit would have been worse off after the market rule change for this day.

Figure 4: Gross and Net Load for June 8, 2016 Simulations

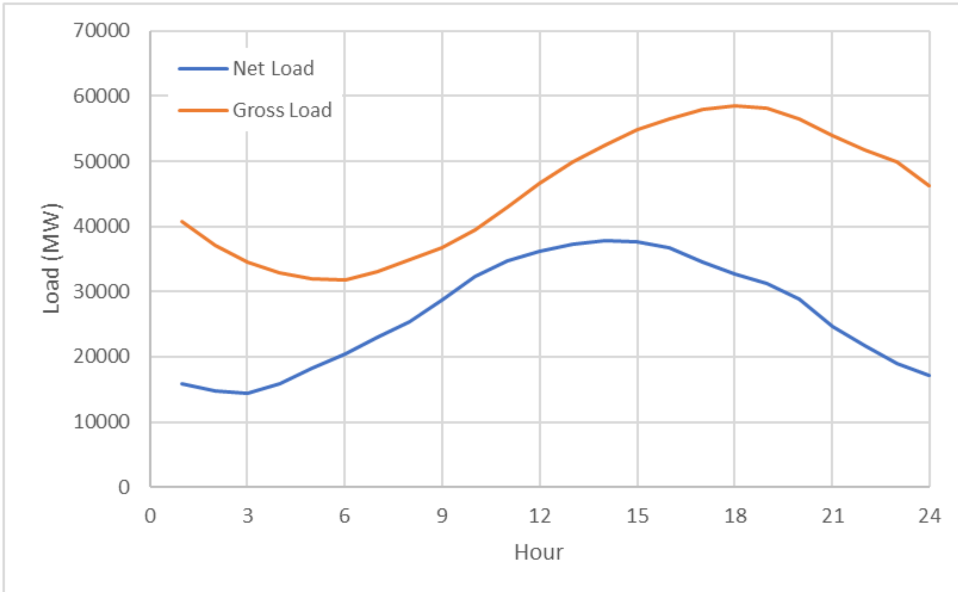


Figure 5: Prices for both ORDC cases for June 8, 2016 Simulations (No Upgrade)

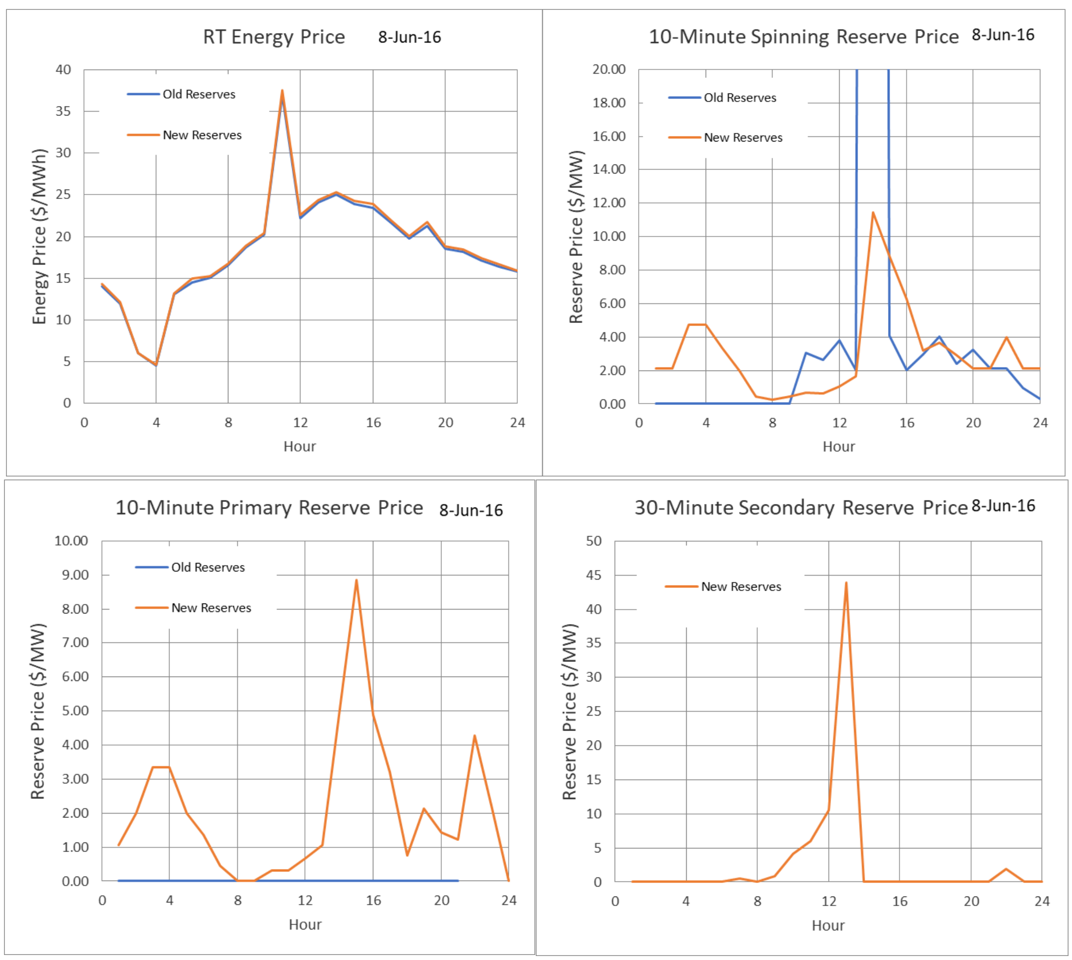


Table 8: Net Revenue to Owner of G35 for June 8, 2016 Simulations

	Reserve Market	All Features	Lower Pmin	Higher Pmax	Faster Start	Faster Ramp
Change in Net Revenue	**Current**	$18K	-$8K	$0.9K	$14K	$0.6K
	Proposed	$40K	$5K	$10K	$22K	$3K
Change due to Reserve Market Design Change	Current Unit -4K	$17K	$9K	$5K	$4K	-$2K

Figure 6 shows the generation from G35 for each hour of the day before and after the ALL upgrade under both reserve market designs. For the current reserve market, the impact of the upgrade is that G35 would start up slightly later (because it starts faster) and begin the evening ramp-down slightly sooner. Under the proposed reserve market, the base version of G35 would remain online overnight at its minimum output in order to provide reserves. However, after the upgrade, the faster startup capability allows the system to take G35 offline overnight (keeping a different unit online to provide the reserves), and then bring it online for the peak hours. The upgraded unit is able to provide more energy during the peak hours and also more reserves (see Figure 7). Under both reserve markets, the upgraded G35 provides more reserves than the base version of the unit.

Figure 6: Generation from G35 on June 8, 2016 (Base vs. All Upgrade, both ORDC cases)

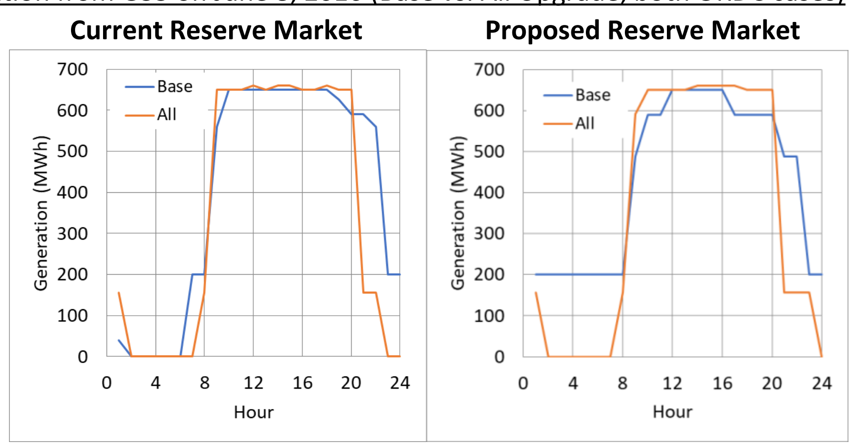


Figure 7: Reserves Cleared from G35 on June 8, 2016 (Base vs. All Upgrade, both ORDC cases)

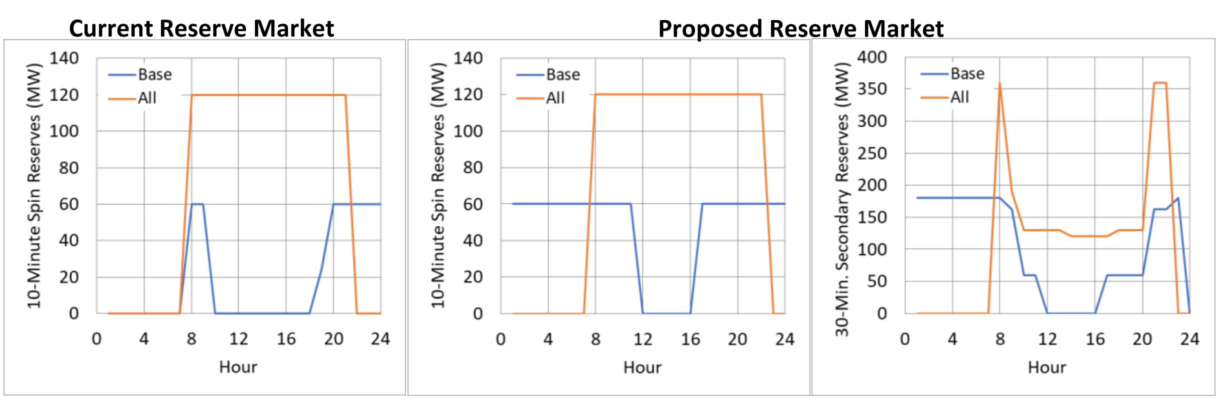
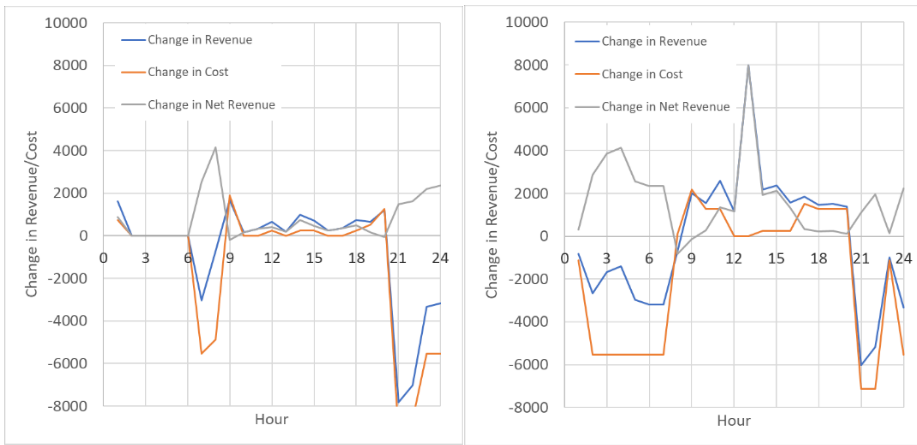


Figure 8: Changes to Revenue, Cost, and Net Revenue for G35 on June 8, 2016 (All Upgrade - Base)

Current Reserve Market **Proposed Reserve Market**



Under the current reserve market design, the increase in net revenue from the upgrade is mainly due to savings from reducing production during less profitable offpeak times. This also occurs under the proposed reserve market, but in addition there is a significant gain in revenue from reserves during the peak hours (1100 – 1700). The breakdown of changes to costs and revenues due to the upgrade are shown in Table 9. Under both reserve designs, the energy revenues and the costs decrease after the upgrade, but under the proposed design, an increase in reserve revenues offsets much of the energy revenue reduction.

Table 9: Changes in Costs and Revenues from ALL Upgrade to Owner of G35 for June 8, 2016

Impact of Upgrade ALL Features	Current	Proposed
Change in Revenue ($)	$36K	$95K
Change in Cost ($)	-$14K	-$14K
Change in Net Revenue ($)	$50K	$109K
Change in Energy Rev ($)	$34K	$90K
Change in Reserve Rev ($)	$2K	$5K
Change in Gen (MWh)	-438	-450
Change in Reserves (MW)	540	480

Example #2: November 22, 2016, G35, Upgrade All Features

The majority of the days on which the gains from upgrading are substantially better under the proposed reserve market relative to the current market are in the spring and fall seasons. As a second example, this section shows the detailed results from November 22, 2016. This day is a representative example of a fall/winter day. The load and net load are relatively low, and the share of generation from wind is large. However, the wind decreases during the overnight hours, requiring dispatchable generation to increase output and leading to a temporary shortage of reserves; the load and net load for this day are shown in Figure 9.

Figure 10 shows the impacts of reserve market change on the base case (no flexibility upgrade) in terms of prices. In the upper left, the real-time LMPs over the simulated day are shown for both ORDC cases, which have minimal differences. The overnight shortage of reserves due to the decrease in wind generation causes price spikes under both market designs. However, the proposed ORDCs would result in higher reserve prices at their peak.

The change in net revenues to the owner of G35 due to the upgrade for the one day are shown in Table 10 for both ORDC cases and for every upgrade case. If G35 has its current capabilities, the net revenue would increase by $45K under current ORDCs and by $217K under the proposed ORDCs. If the owner had already upgraded to the more flexible version, the change in market rules would have substantially increased the net revenue, but the original, less flexible current unit would have been worse off after the market rule change on this day.

Figure 11 shows the generation from G35 for each hour of the day before and after the ALL upgrade under both reserve market designs. For the current reserve market, the impact of the upgrade is that G35 would come online sooner, produce more energy during the two peak periods, and remain at a lower minimum output (providing reserves) at other times. The generation patterns are similar under the proposed reserve market, except that with or without the upgrade, less energy is produced during the first morning peak in order to provide more reserves. Under both reserve markets, the upgraded G35 provides more reserves than the base version of the unit, and can begin providing reserves sooner, taking advantage of the reserve price spike.

Figure 9: Gross and Net Load for November 22, 2016 Simulations

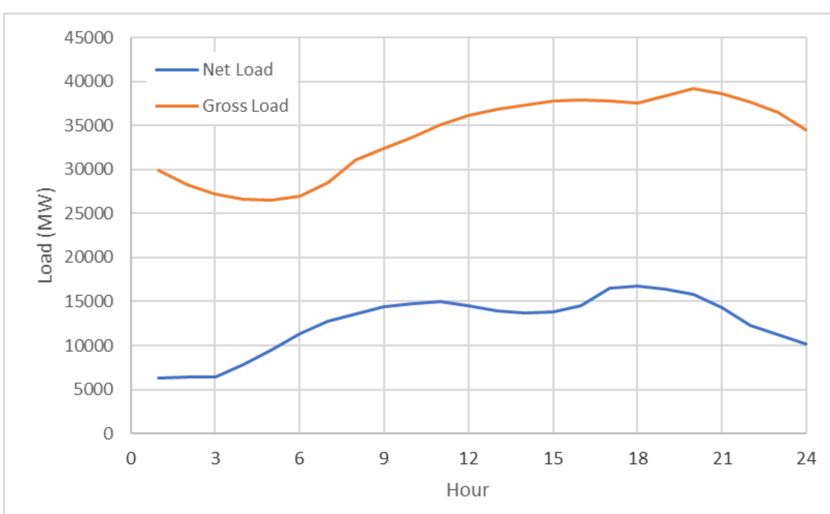


Figure 10: Prices for both ORDC cases for November 22, 2016 Simulations (No Upgrade)

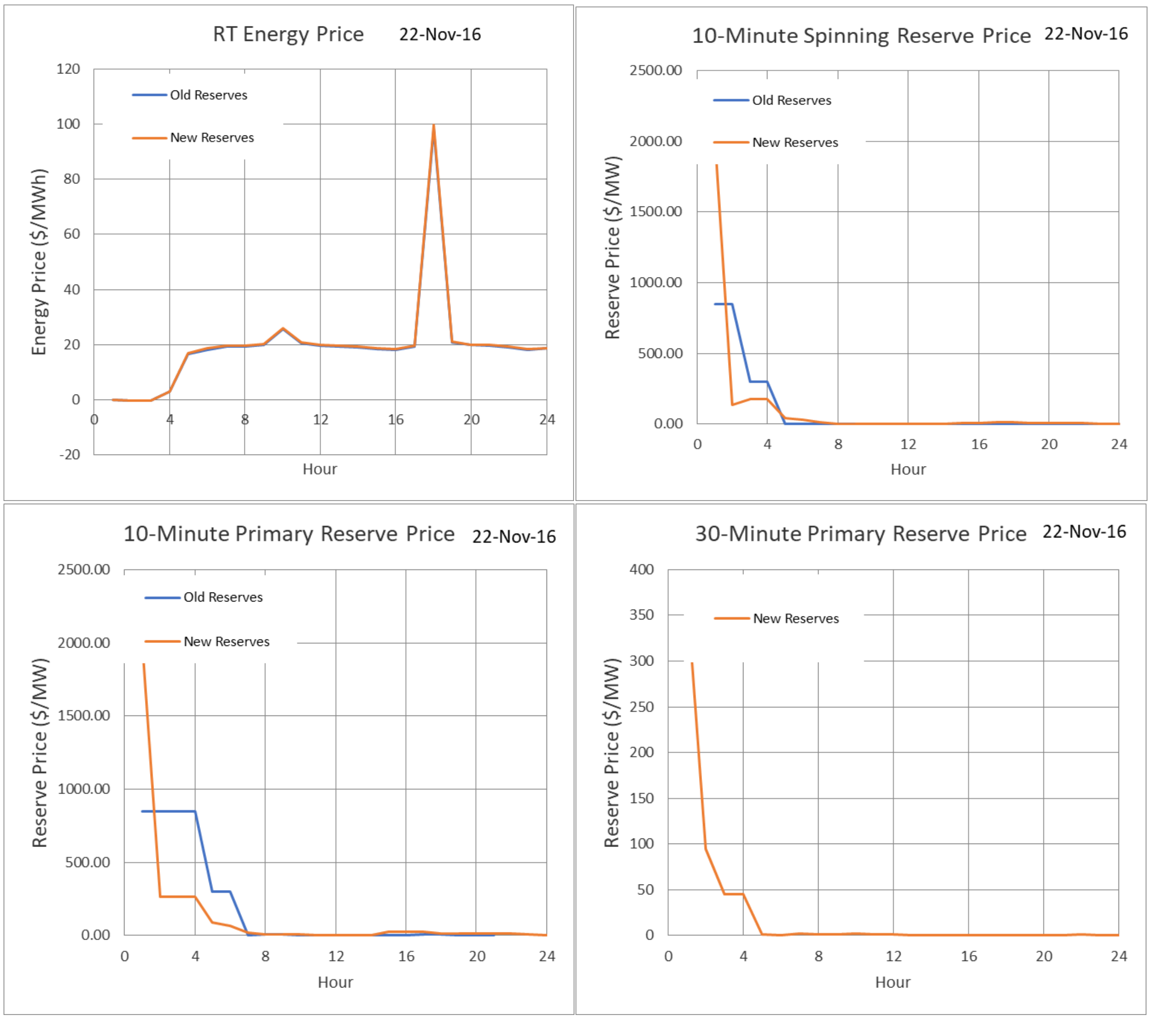


Table 10: Net Revenue to Owner of G35 for November 22, 2016 Simulations

	Reserve Market	All Features	Lower Pmin	Higher Pmax	Faster Start	Faster Ramp
Change in Net Revenue	**Current**	$45K	-$31K	-$27K	$154K	$95K
	Proposed	$217K	$4K	$5K	$42K	$184K
Change due to Reserve Market Design Change	Current Unit -3K	$170K	$32K	$30K	-$114K	$87K

Figure 11: Generation from G35 on November 22, 2016 (Base vs. All Upgrade, both ORDC cases)

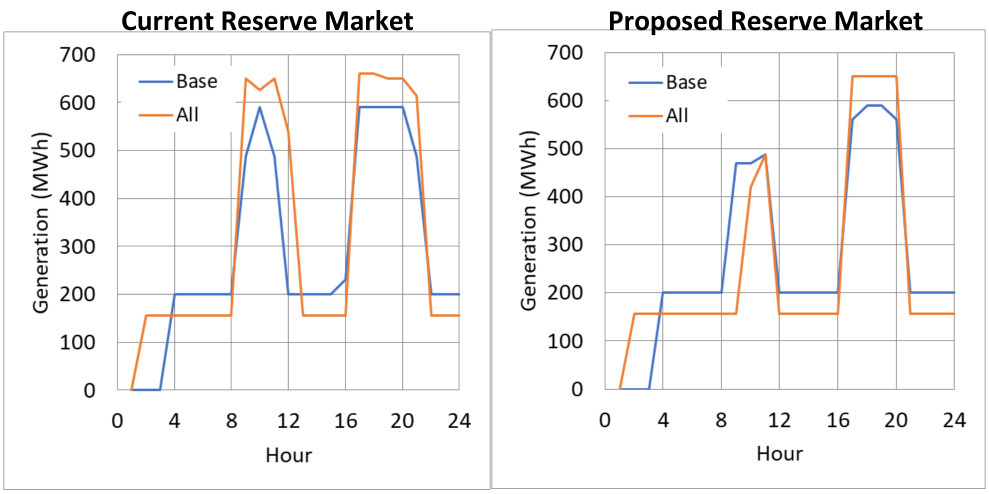


Figure 12: Reserves Cleared from G35 on November 22, 2016 (Base vs. All Upgrade, both ORDC cases)

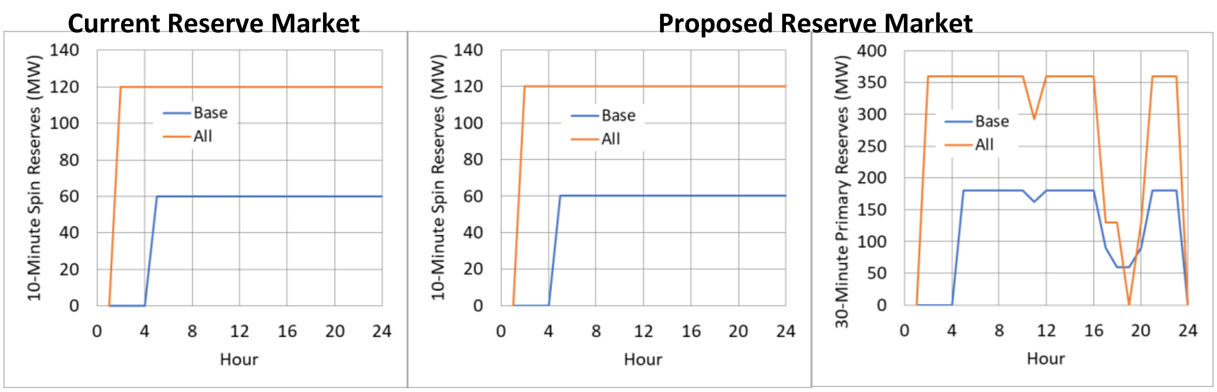
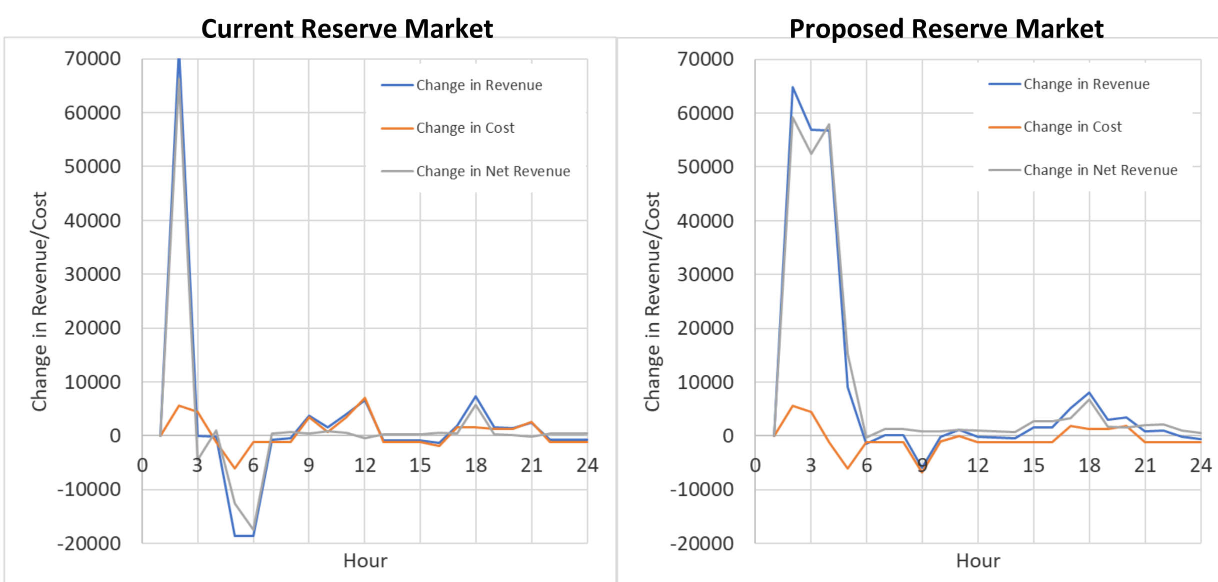


Figure 13: Changes to Revenue, Cost, and Net Revenue for G35 on November 22, 2016 (All - Base)



Under both reserve markets, G35 would increase its net revenue with the greater flexibility by receiving more of the reserve revenue from the price spike in the first few hours of the day. The impact of the proposed reserve market design is a larger increase in the reserve revenues for more hours. The higher reserve prices would reward the flexibility from the upgrade more than the current design.

Table 11: Changes in Costs and Revenues from ALL Upgrade to Owner of G35 for November 22, 2016

Impact of Upgrade ALL Features	Current	Proposed
Change in Revenue ($)	$58K	$204K
Change in Cost ($)	$14K	-$12K
Change in Net Revenue ($)	$45K	$217K
Change in Energy Rev ($)	$18K	-$8K
Change in Reserve Rev ($)	$41K	$213K
Change in Gen (MWh)	841	-368
Change in Reserves (MW)	1560	1560

4. Conclusions

As in all simulation studies, the analysis presented here is a simplified representation of the dynamics involved in scheduling and dispatching of generators in a competitive energy market. Many aspects of actual electricity markets are omitted for simplicity and tractability, such as transmission network flows, strategic bidding by market participants, uncertainty and the adjustments between day-ahead and real-time markets, and many others. Furthermore, the numerical simulations are an artificial experiment, layering a representation of the main features of the ERCOT market with the specific operating reserve market designs (current and proposed) from PJM.

Nevertheless, the results from the simulations suggest a clear directional trend: a change in reserve markets that procures more operational reserves and sets a higher and more gradually increasing penalty on reserve shortages, which induces higher prices, increases the incentives for investments in flexibility. The greater incentive for flexibility is suggested by the increase in net revenue to the generator owner from enhancing flexibility is greater under the proposed reserve market. In addition, the increase in net revenue to the generator from the reserve market design change is greater for the more flexible version of the otherwise identical generator, so the more flexible generators would gain the most from the market design changes.

The greater incentives for flexibility from increased system demand for reserves and higher reserve prices is consistent with how each type of flexibility allows the system to reduce costs. A lower minimum output results in a generator being dispatched lower during off peak times, reducing energy revenues. However, a lower output level and faster ramp rate both allow that unit to provide more reserves. If reserves are priced higher, that can offset some of the losses. If a generator has a higher maximum output, it will be dispatched higher during peak hours to displace less efficient generators. In this situation, the increase in energy prices that is a consequence of the greater demand for reserves would increase the benefit to the generator. The only type of flexibility that receives little benefit from the change in reserves is a faster startup capability. This feature tends to lead to the system scheduling the unit offline for more hours per year, with more startups, and often delays the startup time until later in the day. With fewer hours online, there is less opportunity to receive either energy or reserve revenues.

Several of the omitted aspects of actual power systems would most likely further increase the benefits from increasing flexibility to the system and also would likely increase the gain from a change in the reserve market design. One important factor is uncertainty in load and renewable generation forecasts. If the projected net load over the next few hours from any point in time is greater, the need for flexibility and reserves will increase. If a sudden change in renewable output occurs over a short time, insufficient synchronized reserves would require starting high-cost and inefficient peaking units. If the renewable output increased rapidly, generators that can dispatch lower without shutting down also save the system the costs of starting up again later. The additional benefits under uncertainty would be further increased if examined over smaller time steps than hourly, such as 5-minute or 10-minute increments. Finally, the current trend of an increasing share of energy from wind and solar over the next several years and beyond will also further increase the stress on the dispatchable generators, and will require more flexibility from the units that will likely need to cycle more, ramp more quickly over a wider operating range, and remain financially viable with fewer operating hours.

Changes such as the reserve pricing proposal from PJM will be increasingly needed by RTOs as these trends continue. In the absence of ancillary service market changes or other changes that reward those resources that keep demand and supply in balance and maintain reliability, the technological changes to provide these services are less likely to be adopted.

References

PJM (2018). Price Formation. Report by Energy Price Formation Senior Task Force, December 14, 2018.

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Rewarding Flexibility: An Analysis of the Impact of PJM's Proposed Price Formation Reform on the Incentives for Increasing Generator Flexibility

TECHNICAL APPENDIX

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Model Formulation

This section describes the formulation for the unit commitment model used in this study.

Nomenclature

Sets and Indices

$g \in G$	Generating units
$t, \tau \in T$	Time periods
$j \in J$	Steps in operating reserve demand curve
$k \in K$	Power points for piecewise linear cost
$l \in L$	Startup trajectory time points
$\sigma \in \Sigma$	Startup type, from Hot to Cold

Variables

$p_{g,t}$	Power output of unit *g* in period *t* [MWh]
$w_{g,t}$	Power output above minimum load [MWh]
nse_t	Unmet demand in period *t* [MWh]
$u_{g,t}$	Commitment state for unit *g* at time *t* {0,1}
$v_{g,t}$	Startup indicator for unit *g* at time *t* {0,1}
$z_{g,t}$	Shutdown indicator for unit *g* at time *t* {0,1}
$\lambda_{g,\sigma,t}$	Indicator for startup type σ {0,1}
$f_{g,t}$	Fuel cost for unit *g* at time *t* [$]
$\mu_{g,k,t}$	Amount of power from segment *k* [MW]
$\beta_{g,t}$	Indicator if power > $\underline{P}$ + segment k_1 {0,1}
$r_{g,t}^{10,s}$	Quantity of 10-min spinning reserves provided by unit *g* in period *t* [MW]
$r_{g,t}^{10,n}$	Quantity of 10-min non-spinning reserves provided by unit *g* in period *t* [MW]
$r_{g,t}^{30,s}$	Quantity of 30-min spinning reserves provided by unit *g* in period *t* [MW]
$r_{g,t}^{30,n}$	Quantity of 30-min non-spinning reserves provided by unit *g* in period *t* [MW]
$\rho_{j,t}^{10,s}$	Shortage of 10-min synchronized reserves from step *j* at time *t* [MW]
$\rho_{j,t}^{10,P}$	Shortage of 10-min primary reserves from step *j* at time *t* [MW]
$\rho_{j,t}^{30}$	Shortage of 30-min secondary reserves from step *j* at time *t* [MW]
c_t^R	total penalties for reserves in period *t* [MWh]

Parameters

D_t	Net load at time *t* [MW]
$\overline{P_g}$	Maximum output of generator *g* [MW]
$\underline{P_g}$	Minimum output of generator *g* [MW]
C_g^{vom}	Variable O&M costs, generator *g* [$/mmbtu]
C_g^{fuel}	Price of fuel for generator *g* [$/mmbtu]
$C_{g,\sigma}^{start}$	Startup cost, unit *g*, start type σ [$/MW]
C^{NSE}	Penalty for non-served energy [$/MWh]
TU_g	Minimum uptime for generator *g* [hrs]
TD_g	Minimum downtime for generator *g* [hrs]
RU_g	Ramp limits up for generator *g* [MW/min]
RD_g	Ramp limits down, generator *g* [MW/min]
$PP_{k,g}$	Power output for segment *k* [MW]
$HR_{k,g}$	Incr. heat rate segment *k* [MMBTU/MW]
$T_{g,\sigma}^{su}$	Time since shutdown for startup type σ [hrs]
$R_t^{10,s}$	System requirement for 10-min synchronized reserves at time *t* [MW]
$R_t^{10,P}$	System requirement for 10-min primary reserves at time *t* [MW]
R_t^{30}	System requirement for 30-min secondary reserves at time *t* [MW]
$PR_{j,t}^{10,s}$	ORDC price for 10-min synchronized reserves in step *j* at time *t* [$/MW]
$PR_{j,t}^{10,P}$	ORDC price for 10-min primary reserves in step *j* at time *t* [$/MW]
$PR_{j,t}^{30}$	ORDC price for 30-min secondary reserves in step *j* at time *t* [$/MW]

The model used in this report is a deterministic unit commitment (UC) model, formulated as mixed integer linear program (MILP). Our formulation is based on the tight and compact formulation presented in [Morales-Espana 2013a; 2013b], in particular the startup and shutdown ramp trajectory formulation in [2013b], which is critical to resolve the impacts of faster startup ramping.

The UC model solves for the minimum cost schedule of commitment status and power output from all dispatchable generators subject to balancing supply and demand at every time period and the operational constraints of the generators. The objective function (1) minimizes the total variable costs, which consists of the total generation (fuel and variable O&M) costs, the total startup costs, the cost of non-served energy, and the cost of reserve penalties from the ORDCs. The non-served energy is zero for all solutions, but is included to ensure feasibility.

$$\begin{aligned} \text{Min} \sum_{g \in \boldsymbol{G}} \sum_{t \in \boldsymbol{T}} \left(f_{g,t} + C_g^{vom} p_{g,t}\right) \\ + \sum_{g \in \boldsymbol{G}} \sum_{t \in \boldsymbol{T}} \sum_{\sigma \in \Sigma} \left(C_{g,\sigma}^{start} \lambda_{g,\sigma,t}\right) \\ + \sum_{t \in \boldsymbol{T}} \left(C^{NSE} nse_t\right) \\ + \sum_{t \in \boldsymbol{T}} \left(c_t^R\right) \end{aligned} \tag{1}$$

The supply demand balance constraint is:

$$\sum_{g \in \boldsymbol{G}} p_{g,t} + nse_t = D_t \tag{2}$$

Generator operational constraints include ramping constraints, given in (3) - (5):

$$w_{g,t+1} - w_{g,t} = RU_g * 60 * u_{g,t} \tag{3}$$

$$w_{g,t} - w_{g,t+1} = RD_g * 60 * u_{g,t} \tag{4}$$

$$w_{g,t} = \left(\overline{P_g} - \underline{P_g}\right)\left(u_{g,t} - z_{g,t}\right) \tag{5}$$

Minimum uptime/downtime constraints are given in (6) and (7):

$$u_{g,t} \geq \sum_{\tau = t - TU_g}^{t} z_{g,\tau} \,, \qquad \forall\, t, g \tag{6}$$

$$1 - u_{g,t} \geq \sum_{\tau = t - TD_g}^{t} v_{g,\tau} \,, \qquad \forall\, t, g \tag{7}$$

Commitment, startup, and shutdown indicator logic is in (8):

$$u_{g,t} = u_{g,t-1} + z_{g,t} - v_{g,t} \tag{8}$$

We adopt the formulation from [Morales-Espana 2013b] for startup types (e.g., Hot, Warm, Cold) and startup and shutdown ramp trajectories for generators, which are dependent on startup type. Startup costs $C_{g,\sigma}^{start}$ are also dependent on startup type. Equations (9) – (10) specify these constraints:

$$\lambda_{g,\sigma,t} \leq \sum_{l = T_{g,\sigma}^{su}}^{T_{g,\sigma+1}^{su} - 1} v_{g,t-l} \,, \qquad \forall\, t, g, \sigma \tag{9}$$

$$\sum_{\sigma} \lambda_{g,\sigma,t} = z_{g,t} \,, \qquad \forall\, t, g, \sigma \tag{10}$$

Equation (9) sets the appropriate startup indicator $\lambda_{g,\sigma,t}$from the time duration since the last shutdown, where startup type σ is 1 if there was a shutdown within the interval $[t - T_{g,\sigma}^{su}, t - T_{g,\sigma+1}^{su})$. Constraint (9) is defined for all start-up types except the coldest. Constraint (10) enforces that only one type of start-up is allowed. If none of the startup type indicators are set to 1 by constraint (9), then the coldest startup type is active.

The total power output from the generator is set by constraints (11)-(12):

$$P_{g,t} = \underline{P_g} * u_{g,t} + w_{g,t} + \sum_{l=1}^{SD_g} P_l^{SD} * z_{g,t-l+1} \tag{11}$$

$$+ \sum_{\sigma} \sum_{l=1}^{SU_{g,\sigma}} P_{g,\sigma}^{SU} * v_{g,t-l+SU_g+1} \quad \forall\, t, g, \sigma \tag{12}$$

The first two terms on the rhs of (11) constraint total output to be the minimum output $\underline{P_g}$ plus the power above the minimum $r_{g,t}$ when the unit is committed. The second term follows the shutdown trajectory P_l^{SD} for the SD_g hours after a shutdown is initiated. The last term constrains power to follow the startup trajectory $P_{g,\sigma}^{SU}$ for the first $SU_{g,\sigma}$ hours after a startup of type σ is initiated.

The UC model represents the fuel cost using a piecewise linear incremental heat rate curve, using the formulation in [] that avoids binary variables to indicate the active segment. Each segment *k* indicates the incremental heat rate $HR_{g,k}$ when the generator output is in the interval $(PP_{k,g}, PP_{k+1,g}]$ and the amount of power from segment k is given by

$$f_{g,t} = \sum_{k=2}^{K} HR_{g,k} C_g^{fuel} \mu_{g,k,t} + HR_{g,1} C_g^{fuel} \underline{P_g} \tag{13}$$

$$p_{g,t} = \sum_{k=1}^{K} \mu_{g,k,t} \tag{14}$$

$$\mu_{g,k,t} \le PP_{k,g} \tag{15}$$

This formulation works for strictly convex heat rate curves that increase non-monotonically (not including the no-load heat rate). However, the natural gas combined cycle units with two or more combustion turbines exhibit with non-convex heat rate curves. Rather than convexify, we introduce a single binary variable for each combined cycle generator at each time period, and include the following constraints:

$$\beta_{g,t} \le \frac{\mu_{g,2,t}}{PP_{2,g} - PP_{1,g}} \tag{16}$$

$$\sum_{k=3}^{K} \mu_{g,k,t} \le \beta_{g,t} * \left(PP_{K,g} - PP_{2,g}\right) \tag{17}$$

The representation of reserves and the ORDCs consists of several constraints. Equations (18-20) enforce that system requirements for each reserve type are met or else a penalty scaling with the shortfall is added to the objective function (1). The dual variables associated with these constraints provide the prices used to determine compensation to the generators.

$$\sum_{g=1}^{G} r_{g,t}^{10,s} + \sum_{j=1}^{J} \rho_{j,t}^{10,s} \geq R_t^{10,s} \tag{17}$$

$$\sum_{g=1}^{G} r_{g,t}^{10,s} + \sum_{g=1}^{G} r_{g,t}^{10,n} + \sum_{j=1}^{J} \rho_{j,t}^{10,P} \geq R_t^{10,P} \tag{18}$$

$$\sum_{g=1}^{G} r_{g,t}^{30,s} + \sum_{g=1}^{G} r_{g,t}^{30,n} + \sum_{j=1}^{J} \rho_{j,t}^{30} \geq R_t^{30} \tag{19}$$

The contribution of spinning reserves is constrained by the remaining capacity above current output and by the ramp rate limit of the generator (20-23):

$$w_{g,t} + r_{g,t}^{10,s} \leq \left(\overline{P_g} - \underline{P_g}\right) u_{g,t} \tag{20}$$

$$r_{g,t}^{10,s} \leq u_{g,t} RU_g * 10 \tag{21}$$

$$w_{g,t} + r_{g,t}^{30,s} \leq \left(\overline{P_g} - \underline{P_g}\right) u_{g,t} \tag{22}$$

$$r_{g,t}^{30,s} \leq u_{g,t} RU_g * 30 \tag{23}$$

The penalty from the ORDCs are summed over the steps, summed over reserve types at each hour (24):

$$c_t^R = \sum_{j=1}^{J} \rho_{j,t}^{10,s} PR_{j,t}^{10,s} + \sum_{j=1}^{J} \rho_{j,t}^{10,P} PR_{j,t}^{10,P} + \sum_{j=1}^{J} \rho_{j,t}^{30} PR_{j,t}^{30} \tag{24}$$

The full model is described by the set of equations (1)-(24). The model has been implemented in the GAMS programming language and is solved using CPLEX 12. The model simulations were performed on a LINUX cluster with nodes consisting of 2.8 GHz Intel Xeon Processors, 20 CPU/node, 256 GB RAM, FDR Infiniband, and 40 Gbps Ethernet.

Data and Parameter Assumptions for ERCOT Simulations

The parameter assumptions for the full set of dispatchable generators are provided in Table A.1. Although we do not identify the generators by name, each is based on an existing unit in ERCOT in 2016, and parameters are based on data in eGRID and SNL Energy. Additional data and assumptions can be found in the GitHub archive (http://github.com/mortpsu/PJMFlexibilityStudy).

References

G. Morales-España, J. M. Latorre, and A. Ramos (2013a). Tight and Compact MILP Formulation for the Thermal Unit Commitment Problem. *IEEE Transactions on Power Systems* 28(4): 4897-4908.

G. Morales-España, J. M. Latorre, and A. Ramos (2013b). Tight and Compact MILP Formulation of Start-Up and Shut-Down Ramping in Unit Commitment. *IEEE Transactions on Power Systems* 28(2): 1288-1296.

Table A.1: Generator Parameters															
GEN #	**Generator nameplate capacity (MW)**	**Generator primary fuel**	**Generator prime mover type**	**Gen Type**	**HR Curve Type**	**AVG HEAT RATE**	**FUEL COST ($/MMBTU)**	**Var O&M ($/MWh) (2016)**	**GEN Pmax**	**GEN Pmin**	**MIN UP**	**MIN DOWN**	**Fuel Type**	**Ramp**	**Est Avg Op Costs ($/MWh)**
1	675	SUB	ST	1	1	10080	2.3	2.96	675	335	6	6	1	2	19.54
2	623	SUB	ST	1	1	10599	2.3	2.33	623	181	6	6	1	2	20.45
3	620	SUB	ST	1	1	10599	2.3	2.33	620	190	6	6	1	2	20.45
4	450	SUB	ST	1	1	10599	2.3	2.33	450	210	6	6	1	1	20.45
5	490	SUB	ST	1	1	10749	2.3	3.97	490	165	6	6	1	1	26.52
6	587	SUB	ST	1	1	10086	2.3	3.21	587	142	6	6	1	2	26.53
7	820	SUB	ST	1	1	10086	2.3	3.21	820	324	6	6	1	2	26.53
8	438	SUB	ST	1	1	11197	2.3	4.5	438	141	6	6	1	1.5	29.63
9	415	SUB	ST	1	1	11197	2.3	4.5	415	139	6	6	1	1.5	29.63
10	890	SUB	ST	1	1	10566	2.3	2.56	890	302	6	6	1	1	14.91
11	905	SUB	ST	1	1	10566	2.3	2.56	905	450	6	6	1	1	14.91
12	865	LIG	ST	1	1	11736	2.3	2.9	865	310	4	4	1	2.5	14.35
13	865	LIG	ST	1	1	11736	2.3	2.9	865	335	4	4	1	2	14.35
14	860	LIG	ST	1	1	11736	2.3	2.9	860	305	4	4	1	2.5	14.35
15	890	LIG	ST	1	1	10752	2.3	2	890	485	4	4	1	1	13.23
16	880	LIG	ST	1	1	10752	2.3	2	880	500	4	4	1	1	13.23
17	695	SUB	ST	1	1	10769	2.3	5.38	695	220	6	6	1	1.5	27.51
18	440	LIG	ST	1	1	12804	2.3	2.6	440	253	4	4	1	1	37.8
19	900	SUB	ST	1	1	9331	2.3	2.9	900	380	6	6	1	1.5	18.43
20	175	LIG	ST	1	1	11608	2.3	2.14	175	100	4	4	1	0.3	10.41
21	175	LIG	ST	1	1	11608	2.3	2.14	175	100	4	4	1	0.3	10.41
22	706	SUB	ST	1	1	10531	2.3	2.7	706	179	6	6	1	2	20.16
23	698	SUB	ST	1	1	10531	2.3	2.7	698	178	6	6	1	2	20.16
24	612	SUB	ST	1	1	10531	2.3	2.7	612	178	6	6	1	2	20.16
25	648	SUB	ST	1	1	10531	2.3	2.7	648	176	6	6	1	2	20.16

26	465	NG	2-1 CC	2	3	7250	3	0.98	466	160	2	2	2	1	22.34
27	466	NG	2-1 CC	2	3	7740	3	2.89	466	185	2	2	2	3.2	22.89
28	520	NG	2-1 CC	2	3	7988	3	1	520	150	2	2	2	1	21.81
29	600	NG	2-1 CC	2	3	7458	3	1	600	150	2	2	2	2	20.77
30	470	NG	2-1 CC	2	3	7332	3	1.01	470	150	2	2	2	2	20.22
31	320	NG	2-1 CC	2	3	7825	3	1.88	320	105	2	2	2	2	22.62
32	233	NG	2-1 CC	2	3	8387	3	1.03	233	90	2	2	2	2	22.88
33	240	NG	2-1 CC	2	3	8387	3	1.03	240	90	2	2	2	2	22.88
34	330	NG	1-1 CC	2	2	7447	3	1.67	330	150	2	2	2	1.5	20.95
35	640	NG	3-1 CC	2	3	7397	3	0.83	650	200	2	2	2	6	19.98
36	630	NG	3-1 CC	2	3	7397	3	0.83	650	200	2	2	2	6	19.98
37	518	NG	2-1 CC	2	3	7227	3	0.78	518	150	2	2	2	2	19.48
38	518	NG	2-1 CC	2	3	7227	3	0.78	518	207.2	2	2	2	10	19.48
39	480	NG	2-1 CC	2	3	7210	3	0.91	480	180	2	2	2	6	19.69
40	480	NG	2-1 CC	2	3	7210	3	0.91	480	180	2	2	2	6	19.69
41	215	NG	1-1 CC	2	2	7513	3	1.03	215	86	2	2	2	10	20.6
42	215	NG	1-1 CC	2	2	7513	3	1.03	215	86	2	2	2	10	20.6
43	224	NG	1-1 CC	2	2	7513	3	1.03	215	86	2	2	2	10	20.6
44	227	NG	1-1 CC	2	2	7513	3	1.03	215	86	2	2	2	10	20.6
45	620	NG	2-1 CC	2	3	7323	3	0.95	620	248	2	2	2	10	20.3
46	620	NG	2-1 CC	2	3	7323	3	0.95	620	248	2	2	2	10	20.3
47	267	NG	1-1 CC	2	2	8194	3	4.71	267	106.8	2	2	2	10	27.53
48	610	NG	2-1 CC	2	3	7738	3	2.84	610	290	2	2	2	5	22.82
49	610	NG	2-1 CC	2	3	7738	3	2.84	610	290	2	2	2	5	22.82
50	500	NG	2-1 CC	2	3	7175	3	0.83	550	200	2	2	2	5	19.4
51	550	NG	2-1 CC	2	3	7175	3	0.83	550	200	2	2	2	5	19.4
52	340	NG	2-1 CC	2	3	7293	3	1.1	340	120	2	2	2	10	18.25
53	682	NG	2-1 CC	2	3	7281	3	1.05	682	272.8	2	2	2	3	20.12
54	249	NG	1-1 CC	2	2	7720	3	1.04	249	99.6	2	2	2	10	21.02

55	249	NG	1-1 CC	2	2	7720	3	1.04	249	99.6	2	2	2	10	21.02
56	240	NG	1-1 CC	2	2	7720	3	1.04	249	99.6	2	2	2	10	21.02
57	246	NG	1-1 CC	2	2	7720	3	1.04	249	99.6	2	2	2	10	21.02
58	247	NG	1-1 CC	2	2	7720	3	1.04	249	99.6	2	2	2	10	21.02
59	252	NG	1-1 CC	2	2	7720	3	1.04	249	99.6	2	2	2	10	21.02
60	633	NG	2-1 CC	2	3	7569	3	2.08	633	253.2	2	2	2	10	21.64
61	492	NG	2-1 CC	2	3	7284	3	1.14	492	196.8	2	2	2	10	19.67
62	496	NG	2-1 CC	2	3	7284	3	1.14	492	196.8	2	2	2	10	19.67
63	717	NG	2-1 CC	2	3	7245	3	0.92	717	286.8	2	2	2	10	22.28
64	734	NG	2-1 CC	2	3	7224	3	1.24	734	293.6	2	2	2	10	20.39
65	734	NG	2-1 CC	2	3	7224	3	1.24	734	293.6	2	2	2	10	20.39
66	236	NG	2-1 CC	2	3	8981	3	6.06	236	94.4	2	2	2	10	29.31
67	236	NG	2-1 CC	2	3	8785	3	3.59	236	94.4	2	2	2	10	25.93
68	236	NG	2-1 CC	2	3	8785	3	3.59	236	94.4	2	2	2	10	25.93
69	785	NG	3-1 CC	2	3	6872	3	1.21	785	314	2	2	2	10	19.43
70	130	NG	3-1 CC	2	3	10210	3	8.22	130	30	2	2	2	2	35.57
71	312	NG	1-1 CC	2	2	8080	3	1.41	312	124.8	2	2	2	10	25.77
72	62	NG	1-1 CC	2	2	9544	3	8.22	62	24.8	2	2	2	10	33.22
73	220	NG	4-1 CC	2	3	9731	3	8.22	220	55	2	2	2	3	34.01
74	220	NG	4-1 CC	2	3	9731	3	8.22	220	55	2	2	2	3	34.01
75	845	NG	3-1 CC	2	3	7123	3	1.02	845	338	2	2	2	10	19.9
76	850	NG	3-1 CC	2	3	7381	3	1.07	850	480	2	2	2	6	20.17
77	350	NG	2-1 CC	2	3	6627	3	0.6	350	120	2	2	2	3	16.28
78	285	NG	1-1 CC	2	2	8055	3	2.18	285	114	2	2	2	10	23.17
79	680	NG	2-1 CC	2	3	7275	3	1.22	680	272	2	2	2	10	20
80	704	NG	2-1 CC	2	3	8113	3	1.15	704	281.6	2	2	2	10	22.15
81	195	NG	GT	3	5	11426		6.97	195	50	2	2	2	10	47.29
82	191	NG	GT	3	5	11426		6.97	191	50	2	2	2	10	47.29
83	195	NG	GT	3	5	11426		6.97	195	50	2	2	2	10	47.29
84	52	NG	GT	3	6	13721	3	8.49	52	20.8	2	2	2	10	49.96

85	52	NG	GT	3	6	13721	3	8.49	52	20.8	2	2	2	10	49.96
86	52	NG	GT	3	6	13721	3	8.49	52	20.8	2	2	2	10	49.96
87	52	NG	GT	3	6	13721	3	8.49	52	20.8	2	2	2	10	49.96
88	71	NG	GT	3	6	13770	3	38.63	71	28.4	2	2	2	10	74.74
89	70	NG	GT	3	6	13770	3	38.63	71	28.4	2	2	2	10	74.74
90	69	NG	GT	3	6	13770	3	38.63	71	28.4	2	2	2	10	74.74
91	68	NG	GT	3	6	13770	3	38.63	71	28.4	2	2	2	10	74.74
92	150	NG	GT	3	5	11602	3	2.52	150	60	2	2	2	10	31.6
93	150	NG	GT	3	5	11602	3	2.52	150	60	2	2	2	10	31.6
94	38	NG	GT	3	6	12782	3	3.19	38	15.2	2	2	2	10	37.06
95	38	NG	GT	3	6	12782	3	3.19	38	15.2	2	2	2	10	37.06
96	38	NG	GT	3	6	12782	3	3.19	38	15.2	2	2	2	10	37.06
97	38	NG	GT	3	6	12782	3	3.19	38	15.2	2	2	2	10	37.06
98	54	NG	GT	3	6	17149	3	19.83	54	21.6	2	2	2	10	65.28
99	54	NG	GT	3	6	17149	3	19.83	54	21.6	2	2	2	10	65.28
100	54	NG	GT	3	6	17149	3	19.83	54	21.6	2	2	2	10	65.28
101	64	NG	GT	3	6	17149	3	19.83	54	21.6	2	2	2	10	65.28
102	64	NG	GT	3	6	17149	3	19.83	54	21.6	2	2	2	10	65.28
103	64	NG	GT	3	6	17149	3	19.83	54	21.6	2	2	2	10	65.28
104	90	NG	GT	3	6	10243	3	1.85	90	36	2	2	2	10	28.48
105	87	NG	GT	3	6	10243	3	1.85	90	36	2	2	2	10	28.48
106	45	NG	GT	3	6	11241	3	4.21	45	18	2	2	2	10	38.93
107	46	NG	GT	3	6	11241	3	4.21	45	18	2	2	2	10	38.93
108	44	NG	GT	3	6	11241	3	4.21	45	18	2	2	2	10	38.93
109	46	NG	GT	3	6	11241	3	4.21	45	18	2	2	2	10	38.93
110	68	NG	GT	3	6	16660	3	198.44	68	27.2	2	2	2	10	252.31
111	68	NG	GT	3	6	16660	3	198.44	68	27.2	2	2	2	10	252.31
112	68	NG	GT	3	6	16660	3	198.44	68	27.2	2	2	2	10	252.31
113	68	NG	GT	3	6	16660	3	198.44	68	27.2	2	2	2	10	252.31
114	68	NG	GT	3	6	16660	3	198.44	68	27.2	2	2	2	10	252.31

115	67	NG	GT	3	6	16660	3	198.44	68	27.2	2	2	2	10	252.31
116	72	NG	GT	3	6	11486	3	15.02	72	28.8	2	2	2	10	44.95
117	68	NG	GT	3	6	16182	3	32.77	68	27.2	2	2	2	10	91.54
118	65	NG	GT	3	6	16182	3	32.77	68	27.2	2	2	2	10	91.54
119	68	NG	GT	3	6	16182	3	32.77	68	27.2	2	2	2	10	91.54
120	69	NG	GT	3	6	16182	3	32.77	68	27.2	2	2	2	10	91.54
121	70	NG	GT	3	6	16182	3	32.77	68	27.2	2	2	2	10	91.54
122	104	NG	GT	3	5	14343	3	5.25	104	41.6	2	2	2	10	43.98
123	104	NG	GT	3	5	14343	3	5.25	104	41.6	2	2	2	10	43.98
124	75	NG	GT	3	6	13637	3	23.52	75	30	2	2	2	10	62.12
125	48	NG	GT	3	6	10844	3	5.77	48	19.2	2	2	2	10	34.76
126	48	NG	GT	3	6	10844	3	5.77	48	19.2	2	2	2	10	34.76
127	81	NG	GT	3	6	13330	3	1.44	81	32.4	2	2	2	10	36.77
128	81	NG	GT	3	6	13330	3	1.44	81	32.4	2	2	2	10	36.77
129	47.3	NG	GT	3	6	8643	3	2.07	47.3	18.92	2	2	2	10	28.13
130	47.3	NG	GT	3	6	8643	3	2.07	47.3	18.92	2	2	2	10	28.13
131	47.3	NG	GT	3	6	8643	3	2.07	47.3	18.92	2	2	2	10	28.13
132	47.3	NG	GT	3	6	8643	3	2.07	47.3	18.92	2	2	2	10	28.13
133	47.3	NG	GT	3	6	8643	3	2.07	47.3	18.92	2	2	2	10	28.13
134	47.3	NG	GT	3	6	8643	3	2.07	47.3	18.92	2	2	2	10	28.13
135	45	NG	GT	3	6	12074	3	3.07	45	18	2	2	2	10	34.07
136	58	NG	GT	3	6	17238	3	22.59	58	23.2	2	2	2	10	68.27
137	58	NG	GT	3	6	17238	3	22.59	58	23.2	2	2	2	10	68.27
138	58	NG	GT	3	6	17238	3	22.59	58	23.2	2	2	2	10	68.27
139	58	NG	GT	3	6	17238	3	22.59	58	23.2	2	2	2	10	68.27
140	58	NG	GT	3	6	17238	3	22.59	58	23.2	2	2	2	10	68.27
141	58	NG	GT	3	6	17238	3	22.59	58	23.2	2	2	2	10	68.27
142	48	NG	GT	3	6	11944	3	4.82	48	19.2	2	2	2	10	39.35
143	48	NG	GT	3	6	11944	3	4.82	48	19.2	2	2	2	10	39.35
144	48	NG	GT	3	6	11944	3	4.82	48	19.2	2	2	2	10	39.35

145	48	NG	GT	3	6	11944	3	4.82	48	19.2	2	2	2	10	39.35
146	44	NG	JT	3	6	10217	3	5.92	44	15	2	2	2	10	30.22
147	44	NG	JT	3	6	10217	3	5.92	44	15	2	2	2	10	30.22
148	44	NG	JT	3	6	10217	3	5.92	44	15	2	2	2	10	30.22
149	44	NG	JT	3	6	10217	3	5.92	44	15	2	2	2	10	30.22
150	300	NG	ST	4	4	12490	3	28.06	300	75	2	2	2	10	60.33
151	746	NG	ST	4	4	11078	3	3.72	746	298.4	2	2	2	10	33.08
152	749	NG	ST	4	4	11078	3	3.72	746	298.4	2	2	2	10	33.08
153	320	NG	ST	4	4	11579	3	6.63	320	128	2	2	2	10	41.67
154	404	NG	ST	4	4	11579	3	6.63	320	128	2	2	2	10	41.67
155	234	NG	ST	4	4	11684	3	23.64	234	93.6	2	2	2	10	53.57
156	390	NG	ST	4	4	11684	3	23.64	234	93.6	2	2	2	10	53.57
157	395	NG	ST	4	4	13050	3	8.07	395	158	2	2	2	10	41.91
158	435	NG	ST	4	4	13050	3	8.07	395	158	2	2	2	10	41.91
159	435	NG	ST	4	4	13050	3	8.07	395	158	2	2	2	10	41.91
160	392	NG	ST	4	4	11980	3	14.39	392	156.8	2	2	2	10	45.4
161	523	NG	ST	4	4	11980	3	14.39	392	156.8	2	2	2	10	45.4
162	122	NG	ST	4	4	11600	3	7.29	122	48.8	2	2	2	10	37.31
163	118	NG	ST	4	4	11600	3	7.29	122	48.8	2	2	2	10	37.31
164	568	NG	ST	4	4	11600	3	7.29	122	48.8	2	2	2	10	37.31
165	420	NG	ST	4	4	12662	3	7.59	420	168	2	2	2	10	47.63
166	410	NG	ST	4	4	12662	3	7.59	420	168	2	2	2	10	47.63
167	26	NG	ST	4	4	22335	3	38.39	20	8	2	2	2	10	98.26
168	41	NG	ST	4	4	22335	3	38.39	20	8	2	2	2	10	98.26
169	66	NG	ST	4	4	12522	3	11.59	66	26.4	2	2	2	10	45.54
170	100	NG	ST	4	4	12522	3	11.59	66	26.4	2	2	2	10	45.54
171	200	NG	ST	4	4	12522	3	11.59	66	26.4	2	2	2	10	45.54
172	75	NG	ST	4	4	13293	3	38.39	75	30	2	2	2	10	69.07
173	107	NG	ST	4	4	13293	3	38.39	75	30	2	2	2	10	69.07
174	138	NG	ST	4	4	13293	3	38.39	75	30	2	2	2	10	69.07

175	110	NG	ST	4	4	15212	3	13.15	110	44	2	2	2	10	53.81
176	136	NG	ST	4	4	11365	3	7.42	136	54.4	2	2	2	10	31.74
177	136	NG	ST	4	4	11365	3	7.42	136	54.4	2	2	2	10	31.74
178	351	NG	ST	4	4	11365	3	7.42	136	54.4	2	2	2	10	31.74
179	65	NG	ST	4	4	14448		38.39	65	20	2	2	2	10	75.69
180	65	NG	ST	4	4	14448		38.39	65	20	2	2	2	10	75.69
181	167	NG	ST	4	4	12265	3	23.69	167	66.8	2	2	2	10	55.43
182	502	NG	ST	4	4	12265	3	23.69	167	66.8	2	2	2	10	55.43
183	235	NG	ST	4	4	13038	3	38.39	235	94	2	2	2	10	72.41
184	220	NG	ST	4	4	11779	3	6.34	220	88	2	2	2	10	40.33
185	230	NG	ST	4	4	11779	3	6.34	220	88	2	2	2	10	40.33
186	412	NG	ST	4	4	11779	3	6.34	220	88	2	2	2	10	40.33
187	169	NG	ST	4	4	12355	3	6.24	169	67.6	2	2	2	10	38.99
188	169	NG	ST	4	4	12355	3	6.24	169	67.6	2	2	2	10	38.99
189	273	NG	ST	4	4	12355	3	6.24	169	67.6	2	2	2	10	38.99
190	552	NG	ST	4	4	12355	3	6.24	169	67.6	2	2	2	10	38.99
191	770	NG	3-1 CC	5	3	6651	3	0.85	770	308	2	2	2	10	18.48
192	558	NG	2-1 CC	5	3	7060	3	0.85	558	223.2	2	2	2	10	19.56
193	249	NG	1-1 CC	5	2	7060	3	0.85	249	99.6	2	2	2	10	19.56
194	212	NG	2 -1 CC	5	3	9030	3	8.22	212	84.8	2	2	2	10	30.85
195	768	NG	3-1 CC	5	3	5250	3	0.9	768	307.2	2	2	2	10	13.8
196	867	NG	3-1 CC	5	3	6135	3	0.72	768	307.2	2	2	2	10	16.98
197	469	NG	2-1 CC	5	3	5626	3	1.03	469	187.6	2	2	2	10	15.54
198	1112	NG	5-1 CC	5	3	6481	3	0.77	1112	444.8	2	2	2	10	17.95
199	533	NG	6-1 CC	5	3	5308	3	1.3	533	213.2	2	2	2	10	15.37
200	215	NG	2-1 CC	5	3	7114	3	0.84	215	86	2	2	2	10	19.69
201	495	NG	1-1 CC	5	2	7114	3	0.84	495	198	2	2	2	10	19.69
202	846	NG	3x1	5	3	5003	3	0.86	65	26	2	2	2	10	13.92
203	448	NG	3-1 CC	5	3	5929	3	3.64	448	179.2	2	2	2	10	19.35
204	65	NG	GT	6	6	4904	3	1.44	79.6	31.84	2	2	2	10	14.43

205	75	NG	GT	6	6	4904	3	1.44	79.6	31.84	2	2	2	10	14.43
206	75	NG	GT	6	6	4904	3	1.44	79.6	31.84	2	2	2	10	14.43
207	75	NG	GT	6	6	4904	3	1.44	79.6	31.84	2	2	2	10	14.43
208	109	NG	GT	6	5	4855	3	1.44	109	43.6	2	2	2	10	10.88
209	109	NG	GT	6	5	4855	3	1.44	109	43.6	2	2	2	10	10.88
210	109	NG	GT	6	5	4855	3	1.44	109	43.6	2	2	2	10	10.88
211	109	NG	GT	6	5	4855	3	1.44	109	43.6	2	2	2	10	10.88
212	13	NG	CT	6	6	18745	3	232.24	13	0	2	2	2	10	296.62
213	100	WDS	ST	8	4	16472	2.29	4.34	100	40	4	4	3	1	107.51
214	24	NG	GT	7	6	11315	3	1.44	17.5	7	2	2	2	10	36
215	21	NG	GT	7	6	11600	3	7.29	21	8.4	2	2	2	10	37.31
216	41	NG	GT	7	6	10714	3	2.26	32	12.8	2	2	2	10	29.95
217	10	NG	GT	7	6	11315	3	253.72	10	4	2	2	2	10	501.75
218	11	NG	GT	7	6	11315	3	253.72	10	4	2	2	2	10	501.75
219	8.4	NG	IC	7	6	9463	3	12.08	8.4	0	2	2	2	10	57.71
220	8.4	NG	IC	7	6	9463	3	12.08	8.4	0	2	2	2	10	57.71
221	8.4	NG	IC	7	6	9463	3	12.08	8.4	0	2	2	2	10	57.71
222	8.4	NG	IC	7	6	9463	3	12.08	8.4	0	2	2	2	10	57.71
223	8.4	NG	IC	7	6	9463	3	12.08	8.4	0	2	2	2	10	57.71
224	8.4	NG	IC	7	6	9463	3	12.08	8.4	0	2	2	2	10	57.71
225	8.4	NG	IC	7	6	9463	3	12.08	8.4	0	2	2	2	10	57.71
226	8.4	NG	IC	7	6	9463	3	12.08	8.4	0	2	2	2	10	57.71
227	8.4	NG	IC	7	6	9463	3	12.08	8.4	0	2	2	2	10	57.71
228	8.4	NG	IC	7	6	9463	3	12.08	8.4	0	2	2	2	10	57.71
229	8.4	NG	IC	7	6	9463	3	12.08	8.4	0	2	2	2	10	57.71
230	8.4	NG	IC	7	6	9463	3	12.08	8.4	0	2	2	2	10	57.71
231	8.2	NG	IC	7	6	22335	3	38.39	8.2	0	2	2	2	10	98.26
232	8.2	NG	IC	7	6	22335	3	38.39	8.2	0	2	2	2	10	98.26
233	8.2	NG	IC	7	6	22335	3	38.39	8.2	0	2	2	2	10	98.26
234	18.7	NG	IC	7	6	9235	3	7.11	18.7	0	2	2	2	10	117.88

235	18.7	NG	IC	7	6	9235	3	7.11	18.7	0	2	2	2	10	117.88
236	18.7	NG	IC	7	6	9235	3	7.11	18.7	0	2	2	2	10	117.88
237	18.7	NG	IC	7	6	9235	3	7.11	18.7	0	2	2	2	10	117.88
238	18.7	NG	IC	7	6	9235	3	7.11	18.7	0	2	2	2	10	117.88
239	18.7	NG	IC	7	6	9235	3	7.11	18.7	0	2	2	2	10	117.88
240	18.7	NG	IC	7	6	9235	3	7.11	18.7	0	2	2	2	10	117.88
241	18.7	NG	IC	7	6	9235	3	7.11	18.7	0	2	2	2	10	117.88
242	18.7	NG	IC	7	6	9235	3	7.11	18.7	0	2	2	2	10	117.88
243	18.7	NG	IC	7	6	9235	3	7.11	18.7	0	2	2	2	10	117.88
244	18.7	NG	IC	7	6	9235	3	7.11	18.7	0	2	2	2	10	117.88
245	18.7	NG	IC	7	6	9235	3	7.11	18.7	0	2	2	2	10	117.88

CERTIFICATE OF SERVICE

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

Dated at Washington, D.C., this 21st day of June 2019.

/s/ *Elizabeth P. Trinkle*

Elizabeth P. Trinkle

Attorney for PJM Interconnection, L.L.C.