

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

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Docket No. EL19-58-000

**ENHANCED PRICE FORMATION
IN RESERVE MARKETS OF
PJM INTERCONNECTION, L.L.C.**

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March 29, 2019

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March 29, 2019

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

Re: *Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C.*
Docket No. EL19-____-000

Dear Secretary Bose,

Pursuant to section 206 of the Federal Power Act (“FPA”),¹ PJM Interconnection, L.L.C. (“PJM”) hereby submits proposed revisions to the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement”)² to effectuate enhanced price formation in PJM’s reserve markets.

PJM requests an effective date of June 1, 2020, for the revisions contained herein. In order to afford PJM sufficient time to implement the proposed revisions, including the necessary software changes, PJM respectfully requests an order from the Commission by no later than December 15, 2019.

¹ 16 U.S.C. § 824e (2017). The proposed revisions to the Operating Agreement are submitted pursuant to FPA section 206, while PJM is separately submitting the proposed revisions to the PJM Open Access Transmission Tariff (“Tariff”) pursuant to FPA section 205. Since the proposed substantive revisions to the Tariff are identical to the proposed substantive revisions to the Operating Agreement, PJM recognizes that the Commission has found that it is not held to the 60-day notice period in section 205 in cases when the proposed revisions are identical and in both PJM’s Operating Agreement and Tariff. See, e.g., *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,091 at n.4 (2014). PJM is filing this package separately under section 205 and 206 consistent with the Commission’s eTariff filing rules. *Id.*

² The Tariff and Operating Agreement are currently located under PJM’s “Intra-PJM Tariffs” eTariff title, available here: <https://etariff.ferc.gov/TariffBrowser.aspx?tid=1731>. Terms not otherwise defined herein shall have the same meaning as set forth in the Tariff, Operating Agreement, and the Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region (“RAA”). All references to the Operating Agreement, Schedule 1 herein shall also be meant to reference the identical provisions in Tariff, Attachment K-Appendix.

PJM also respectfully requests that the Commission establish an extended comment date of May 15, 2019, which is 47 days from the date of filing, to afford participants sufficient time to review and comment on the proposed changes to PJM's reserve markets.

I. EXECUTIVE SUMMARY

Reserves play an essential role in maintaining reliability. Load and generation must be kept in fairly tight balance at all times, yet advance forecasts of expected load and generation routinely err—in either direction—and system operators must live with the ever-present risk that one or more elements of the bulk power system could trip offline unexpectedly. The obvious, and necessary, solution to managing these uncertainties is to line up resources that are not scheduled to serve load during the target period, but that are capable of providing energy on fairly short notice if needed (i.e., reserves). The Commission recognized as much early in the open access transmission era, when it established spinning reserve service and supplemental reserve service as two of the essential ancillary services that customers must provide or purchase.³

For its part, PJM has long had extensive Tariff rules designed to ensure that necessary reserves are obtained, and the parties that supply those reserves are fairly compensated. Reserve requirements, procedures to meet those requirements, and reserve products to fill those needs, have grown and evolved in the PJM Region in the last twenty-plus years—sometimes in complex ways. A common theme in that evolution for the PJM Region has been extensive reliance on competitive markets with transparent clearing prices intended to reflect the value of these

³ *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC ¶ 61,080, FERC Stats. & Regs. ¶ 31,036 at 31,708 (1996) (“Spinning reserve is provided by generating units that are on-line and loaded at less than maximum output. They are available to serve load *immediately* in an unexpected contingency, such as an unplanned outage of a generating unit. Supplemental reserve is also generating capacity that can be used to respond to contingency situations. Supplemental reserve, however, is not available instantaneously, but rather within a short period (usually ten minutes).”).

reliability services, open to sellers of resources that meet Tariff-defined criteria for reserve products needed for PJM to meet its reliability responsibilities.

But as with any evolution of complex systems, flaws can develop and become more apparent, and more consequential, the longer they are left unaddressed.⁴ Several such flaws, potentially quite consequential as PJM's resource mix changes, have developed within the PJM system of reserve requirements, products, and markets, prompting this filing seeking necessary corrective action. For the reasons described at length in this filing, these flaws are unique to PJM, and the proposed necessary changes described in this filing should not imply that the reserve products and methods of other Regional Transmission Organizations ("RTOs") are unjust and unreasonable.

In particular, this filing focuses on three significant areas of PJM's reserve market design that no longer support efficient market outcomes nor provide the support for reliable operations. Left unaddressed, PJM's reserve markets lead to unjust and unreasonable rates that are unduly discriminatory and preferential. The market enhancements proposed in this filing address the following flaws:

- A Synchronized Reserve product that is separated in to two products – Tier 1 and Tier 2 – with disparate rules around commitment, compensation, and performance penalties;
- An Operating Reserve Demand Curve ("ORDC") which fails to incentivize reserve performance due to the inadequate level of the penalty factor and the shape of the curve; and
- The misalignment of reserve products between the day-ahead and real-time markets which does not adequately procure forward reserves and leads to inefficient commitment and pricing outcomes.

⁴ As discussed later, Commission staff has recognized these flaws itself, and the need for potential reform, in a series of papers developed in 2014 and 2015 in Docket No. AD14-14-000, *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*.

As summarized below and as PJM demonstrates herein through affidavits and data submittals, the flaws in this market design warrant prompt and meaningful attention.

A. *The Current Reserve Market Design Is No Longer Just and Reasonable.*

As currently structured, PJM's reserve markets are not delivering the benefits the Commission has identified from "better formed prices [that] help ensure just and reasonable rates," which include:

- "providing appropriate incentives for market participants to follow commitment and dispatch instructions[;]"
- "maintain[ing] reliability[;]"
- "provid[ing] 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[;]" and
- "encourage[ing] efficient investments in facilities and equipment."⁵

More specifically, as the Commission's advisory staff explained in its 2014 report on shortage pricing, "[a] failure to properly reflect in market prices [(i)] the value of reliability to consumers and [(ii)] 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 "Ideally," the 2014 Commission Staff Shortage Pricing Report explained, market prices when the system fails to meet minimum operating reserve requirements, "would reflect the valuation consumers place on avoiding an involuntary load curtailment," such that "prices should rise, inducing performance of existing supply resources and encouraging load to reduce

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) ("Order No. 825").

⁶ FERC Staff, *Staff Analysis of Shortage Pricing in RTO and ISO Markets*, Docket No. AD14-14-000 (Oct. 21, 2014), at 1, <https://www.ferc.gov/legal/staff-reports/2014/AD14-14-pricing-rto-iso-markets.pdf> ("2014 FERC Staff Shortage Pricing Report").

consumption.”⁷ Absent that ideal of direct end-user valuation of avoiding curtailment, system operators like PJM “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.”⁸ But when the RTO’s “administrative pricing rules” fail to reflect either or both of “the value of reliability to consumers” and the “operator actions taken to ensure reliability,” leading to “inefficient prices”; “inefficient system utilization”; and “muted investment signals,”⁹ then the circumstances require, as Order No. 825 instructed, “better formed prices [to] help ensure just and reasonable rates.”¹⁰

Such circumstances are plainly evident in PJM’s current reserve markets, based on facts specific to the PJM Region and design flaws specific to the PJM reserve market rules, as summarized here and detailed in Section II, below.

1. *Most resources providing Synchronized Reserve are undercompensated in an unduly discriminatory manner.*

Under PJM’s current rules, a substantial share of the Synchronized Reserves (i.e., “Tier 1” Synch Reserves) needed to meet minimum requirements are expected to be provided essentially at no charge, and with no consequences for a failure to respond. This flaw, unique to the PJM Region, directly suppresses the price of needed reserves (by deeming much of the needed minimum quantity to be met at zero cost). Price suppression was plainly evident in very low reserve market clearing prices during notable high load conditions earlier this year. The

⁷ *Id.* See also Affidavit of Drs. William W. Hogan and Susan L. Pope on Behalf of PJM Interconnection, L.L.C. (“Hogan & Pope Aff.”), Attachment C herein, which adopts the analysis and all findings and conclusions contained in the report included as Exhibit 1 to the affidavit entitled “PJM Reserve Markets: Operating Reserve Demand Curve Enhancements” (Mar. 22, 2019), including the Appendix thereto, to provide support for PJM’s proposal to reform its ORDC (“PJM ORDC Report” which is referred to herein as the Hogan & Pope PJM ORDC Report).

⁸ *Id.*

⁹ *Id.*

¹⁰ Order No. 825, 155 FERC ¶ 61,276 at P 163.

reserve product was not oversupplied; rather, it was being supplied in large part by sellers with no obligation to perform. The current Tier 1 rules also inject unpredictability, into the expected response from a substantial share of the reserves that are nominally devoted to helping meet the minimum requirement. PJM's inability to know accurately at any given time the amount of reserves expected to respond will continue to challenge PJM as the system operator and only grow as a problem as the system incorporates increasing levels of variable resources. While energy output can be easily measured, reserve capability cannot, especially when response is voluntary. This inaccuracy negatively impacts markets as well, because energy and reserve prices are dependent on accurate knowledge of system conditions.

2. *Operator actions needed to manage uncertainty in support of reliability result in muted energy and reserve market price signals.*

PJM dispatchers regularly bias (i.e., effectively adding (or reducing) demand that must be balanced with additional (or less) supply) their scheduling of supply resources in an attempt to manage the uncertainty inherent in near-term forecasts of load, wind generation, and solar generation (or for unexpected plant outages), and taking other out-of-market actions to preserve reliability. These operator actions relate directly to the possibility that the PJM system could fall short of minimum reserve requirements ("MRRs"), but the need that motivates the bias is not accounted for in reserve or energy market clearing prices. Given that such operator bias and resource-specific dispatch directives are motivated by reliability concerns, it is *always* a concern that they are not reflected in market prices. But it is *especially* a concern when such actions prevent the market from seeing what would otherwise be reserve shortages—which has happened on the PJM system, as shown below.

3. *PJM's current ORDC does not address the uncertainties around load, wind and solar forecasts or unanticipated plant outages, thus driving the need for the operator actions.*

As a corollary to the second point, PJM's administrative pricing rule intended to address the failure to meet MRRs, i.e., PJM's current ORDC, largely does not address the uncertainties around load, wind and solar forecasts, and unanticipated plant outages¹¹ that PJM dispatchers currently attempt to address through scheduling bias or other out-of-market actions. That omission is material because, in the PJM Region, dispatchers are taking those actions to manage the possibility that real-time conditions departing from those forecasts could harm PJM's ability to meet MRRs. These operator actions should be reflected in clearing prices, consistent with the Commission's policies on appropriate price formation. Reflecting in the ORDC the uncertainties now addressed through operator actions results in a curve that slopes downward and to the right, as discussed in detail below.

4. *Reserve market clearing prices do not reflect the operational value of flexibility.*

Current reserve market clearing prices—zero in about 60 percent of all hours for Synchronized Reserve and in about 98 percent of all hours for Non-Synchronized Reserve—do not reflect the operational value of resource flexibility. That flexibility is today procured through operator actions but is more appropriately reflected in prices. Proper price formation in this area is important today and will become even more important with the expected growth of wind and solar resources. As shown below, even conservative estimates based mostly on currently enacted mandatory Renewable Portfolio Standards (including minimum solar carve-outs) indicate the PJM Region will see an additional 25,000 MWs of wind and an additional 12,000 MWs of solar

¹¹ PJM's current ORDC does include a 190 megawatt ("MW") second step (at a price of \$300/megawatt hour ("MWh")), as a buffer against large dispatch/price excursions. This step does not attempt, however, to value reserves with respect to their benefit to system reliability or to overtly track the relevant operator actions.

resources (with approximately 8,000 MWs of that total behind-the-meter) by 2034. These high absolute MW levels of added intermittent resources indicate a need for a much greater level of flexible resources to help manage the variable output of intermittent resources. While PJM is not unique in the penetration levels of such resources, other regions with high renewable penetration like the MidContinent Independent System Operator, Inc. (“MISO”) and Southwest Power Pool, Inc. (“SPP”) comprise (to a much greater degree than in the PJM Region) vertically integrated utilities with rate-regulated generation assets that are backed up with traditional regulation as a means to assure revenue recovery. PJM is reliant on accurate and effective price signals to incentivize penetration and competition of all resources to provide flexibility. The suppressed signals in the PJM reserve markets today will not accomplish that.

5. *The current \$850/MWh Reserve Penalty Factor is inadequate.*

The ORDC’s current \$850/MWh price ceiling is below the legitimate opportunity cost some PJM Region supply and demand resources could face in shortage or near-shortage conditions, given price levels allowed in the PJM energy market for such resources. The current ORDC therefore prevents the market from clearing at levels that reflect the incremental costs of resources the system needs to maintain MRRs. The possibility that paying all cleared resources the marginal cost of the last resource needed to meet the reserve requirement does not render unreasonable a change from the current “pay as bid” rule for resources costing over \$850/MWh, as explained further below. The Commission’s long-standing policy favoring single-clearing price markets is supported by experience in the PJM Region and elsewhere that such markets do promote market efficiency and competition among marginal-cost sellers.

6. *Misalignment in the day-ahead and real-time reserve markets results in inadequate forward procurement and related market inefficiencies.*

PJM currently has no reserve market valuing 30-minute flexibility in real-time, even though PJM maintains a calculation that estimates real-time 30-minute reserves, for situational awareness purposes. Nor does PJM have a reserve market that procures on a forward basis the 10-minute reserves the system currently relies on in real-time. As explained below, this lack of forward procurement and reserve market alignment is inadequate, creates modeling discrepancies, and inefficient price and resource commitment outcomes.

B. PJM's Proposed Reserve Market Modifications Are Just and Reasonable.

To address and resolve the aspects of the current reserve market rules that are unjust and unreasonable, PJM proposes to:

- consolidate the Tier 1 and Tier 2 products into one product, called “Synchronized Reserve,” with uniform commitment, compensation, and performance obligations to meet all Synchronized Reserve needs;
- revise the current ORDC by:
 - raising the Reserve Penalty Factor to \$ 2,000/MWh, to recognize that sellers could have legitimate opportunity costs up to that level during shortage conditions from foregoing energy market sales (or load reductions) in order to commit as reserves;
 - changing the ORDC curve shape based on a systematic, probabilistic quantification of the same categories of load and supply uncertainties that PJM operators are currently trying to address when they bias dispatch schedules or take other out-of-market actions to guard against PJM falling short of its MRRs; and
- align the day-ahead and real-time reserve markets to ensure that the reserves needed for real-time operation are recognized on a forward basis during the scheduling processes for the next operating day.

PJM explains and justifies each of these proposed changes in detail in Section III, herein, but provides this overview to elaborate on several important aspects of these changes, and their benefits.

1. *Exclusive reliance on a unified and consolidated product for Synchronized Reserve*

The consolidation of the Tier 1 and Tier 2 products simply means that PJM will conform Synchronized Reserves to PJM's treatment of all other products that are obtained to meet reliability needs, i.e., explicit commitments of reserve MWs by sellers; clearing prices and compensation determined on a market basis that maximizes social welfare; and economic consequences for failure to perform. The consolidated product will extend these attributes to all Synchronized Reserves PJM needs to meet its Synchronized Reserve Requirement.

Consolidation of Tier 1 and Tier 2 will also eliminate the operational uncertainty inherent in the current reliance on a product that has no explicit obligation to perform—Tier 1. As shown in Section II.A, below, piecemeal changes aimed at better guessing whether a product that does not need to respond will in fact respond have been ineffective. The obvious solution is to require performance through clear MW commitments, market compensation, and penalties for failure to perform. This solution will also eliminate the price suppression inherent in the current practice of deeming much of the reserve requirement to be met by resources that are not paid for reserves and need not perform when called.

2. *Increasing the Reserve Penalty Factor to \$2,000/MWh*

The current \$850/MWh Reserve Penalty Factor, as shown in Section II.B, prevents the reserve market clearing price from reflecting the incremental costs of resources needed to meet reserve requirements in shortage or near-shortage conditions. Given that the Reserve Penalty Factor is intended to be the key mechanism for setting and signaling shortage pricing in the PJM Region, this is a fundamental flaw. The \$850/MWh therefore is unjust and unreasonable and should be increased. PJM acknowledges that there is no single right answer to the level of that increase; and that a reasonable level for the PJM Region may (and almost certainly will) differ

from a reasonable level for other market areas. For the PJM Region, a reasonable level would take account of the revenues a seller foregoes by committing to provide reserves, rather than sell energy, during shortage or near-shortage conditions. Currently, generation resources can submit verified cost-based incremental energy offers that set clearing prices at levels of up to \$2,000/MWh; emergency energy purchases from neighboring regions likewise can offer above the \$2,000/MWh level, but PJM proposes to cap the ability of such resources to set price at the \$2,000/MWh level under the proposed market rules. Similarly, emergency and pre-emergency demand response can submit offers (and set clearing prices) up to \$1,849/MWh to reduce demand with 30-minutes lead time. A Reserve Penalty Factor of \$2,000/MWh therefore is reasonably viewed—for the PJM Region—as 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. This change, along with the change to the ORDC shape discussed below, will also allow the PJM Region to ensure that the value of resource flexibility is better reflected in clearing prices. More accurate signaling of when and where that flexibility is needed will incent greater development and provision of more flexible resources—allowing the PJM Region to take maximum advantage of a changing resource portfolio mix.

Under the current rules, Reserve Penalty Factors apply separately to satisfaction of each MRR, and recognize zonal reserve shortages that arise from constraints on relying on reserves in one part of the system to meet reserve shortages in other parts of the system. Moreover, because (to satisfy reliability standards) reserves must be maintained for each minimum requirement and for each constrained location, under the current rules Reserve Penalty Factors triggered by each requirement and locational shortage are additive, albeit capped. PJM’s proposal retains the additivity approach, and conforms it to reflect the reserve products proposed in this filing.

However, PJM proposes to remove the cap as it arbitrarily suppresses the price for reserves when the cascading of shortages on the system indicate such reserves are most needed. While this implies that prices could rise as high as \$12,000/MWh,¹² that maximal pricing result: (i) can occur only from the simultaneous occurrence and confluence of multiple product and locational shortages; (ii) is necessary to recognize the independent value of avoiding each such shortage; (iii) implies very extreme conditions that demand immediate supplier response; (iv) likely approximates consensus estimates of the value to load of avoiding curtailment; and (v) logically applies the current approved approach to the reserve products and Reserve Penalty Factors proposed in this filing.

3. *Modifying the ORDC to reflect systematically the varying risks of falling below the MRRs*

The Commission has already recognized, by approving PJM's current ORDC, that there is positive value to committing reserves in excess of the MRR. However, as shown in Section II.B, the current curve does not systematically quantify or recognize that value. Stated succinctly, the value of reserves above the minimum requirement is based on the likelihood that real-time conditions will depart from those expected shortly (e.g., 30 minutes to one hour) before, in a way that results in PJM falling short of the minimum requirement in real-time. Generally speaking, that likelihood is greatest when only, for example, a single MW is committed above the minimum requirement, and the likelihood of falling short is reduced as more reserves are committed. As PJM shows through the Affidavit of Mr. Christopher Pilog, Director, Dispatch,¹³ the onus of recognizing and managing this uncertainty today falls largely

¹² PJM notes this could rise to \$14,000/MWh if PJM models a sub-zone for the 30-minute requirement, but as a default PJM intends to only model the 30-minute reserve requirement for the RTO-wide Reserve Zone.

¹³ Affidavit of Christopher Pilog on Behalf of PJM Interconnection, L.L.C. ("Pilog Aff."). The Pilong Aff. is included as Attachment E herein.

on PJM dispatchers, who bias their schedules, or take other out-of-market actions, to help ensure (among other reliability objectives) that the PJM Region will not fall short of MRRs. Those out-of-market actions suppress clearing prices, fail to correctly recognize the essential value of reserves in managing uncertainty, and increase out-of-market uplift.

To replace the current unjust and unreasonable ORDC, PJM proposes revised curves that are defined directly by the very same supply and demand uncertainties that PJM system operators are attempting to address, i.e., errors in forecasts of load, interchange, thermal plant outages, and wind and solar output. As detailed in the Affidavit of Dr. Patricio Rocha Garrido, Senior Engineer, Resource Adequacy Planning,¹⁴ PJM has calculated these forward uncertainties (30-minute look-ahead for every five minutes, 60 minute look ahead every 15 minutes) for three calendar years of actual PJM Region data. The observed historical combined net error for these specific (and most impactful) operational uncertainties directly define the shape and slope of the ORDCs PJM proposes here. To even more closely reflect the value of this uncertainty, PJM proposes different curves for six different time-blocks in each season, based on the observed three-year historic net error for each of those time blocks. Importantly, PJM also includes the observed impact of regulation service, which directly reduces the likelihood of falling short of reserves.

Systematically defining and valuing reserve uncertainty as proposed here will reduce the need for the current operator actions that attempt to address these uncertainties out of the market. As PJM shows through the Affidavit of Mr. Adam Keech, Executive Director, Market Operations,¹⁵ reducing the need for such operator actions also will directly reduce the out-of-

¹⁴ Affidavit of Dr. Patricio Rocha Garrido on behalf of PJM Interconnection, L.L.C. (“Rocha Garrido Aff.”). The Rocha Garrido Aff. is included as Attachment F herein.

¹⁵ Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C. (“Keech Aff.”). The Keech Aff. is included as Attachment D herein.

market uplift cost of managing around that uncertainty.¹⁶ As detailed below, pricing this uncertainty also will provide a powerful incentive to resources, particularly flexible resources, to meet this market-defined reliability need at the most efficient cost.

4. *Alignment of day-ahead and real-time reserve markets*

As explained in Section II.C, PJM's day-ahead and real-time markets for reserves currently are out of alignment. The resulting modeling discrepancies create inefficiencies in operations and market outcomes, including prices and congestion, as well as opportunities for gaming-type behavior. To address these concerns, and to better support the other necessary elements of this filing that will result in procurement of more reserves, PJM proposes to amend its market rules to procure, in both the day-ahead and real-time markets, one 30-minute reserve product ("Secondary Reserve") and two 10-minute reserve products (Synchronized and Non-Synchronized Reserve). Specifically, PJM proposes to add the 10-minute reserve requirements to the day-ahead market, and the 30-minute reserve requirement to the real-time market.

All reserve products will be procured using ORDCs based on the principles discussed above and using PJM's joint co-optimization algorithm¹⁷ to achieve the least-cost solution. To minimize modeling differences between the day-ahead and real-time markets, for each reserve product, PJM will use the same ORDCs in both markets.

¹⁶ See, e.g., Keech Aff. ¶¶ 38-45, Tables 3 & 4 (showing reduction in uplift under PJM's proposal).

¹⁷ Co-optimization of energy, synchronized reserves and non-synchronized reserves along with ORDCs have been in place in PJM since the implementation of shortage pricing pursuant to Order No. 719 in 2012.

II. PJM'S CURRENT RESERVE MARKET CONSTRUCT IS UNJUST AND UNREASONABLE.

A. PJM's Two-Tier Synchronized Reserve Construct Is Unjust and Unreasonable.

1. Overview of the current Tier 1/Tier 2 structure

Under PJM's current market rules, there are two types of Synchronized Reserve products, Tier 1 and Tier 2. The combination of the Tier 1 and Tier 2 products is used to meet the Synchronized Reserve Requirement.

Tier 1 is provided from non-emergency resources that are on-line and generating, but not fully loaded, and that can provide additional energy within 10 minutes with no departure from their energy profit maximizing economic dispatch point.¹⁸ A simple example of a Tier 1 resource would be a partially loaded generator that has remaining capability to increase its output in response to PJM's request to deploy reserves. Pursuant to the Operating Agreement, all resources meeting the definition of Tier 1 are "deemed to be available" to provide Tier 1.¹⁹ Generation owners do not need to submit sell offers for their resources to be selected to provide Tier 1. Importantly, there is no penalty assessed if a Tier 1 resource is selected as one of the resources used to satisfy the reserve requirement, but the resource then fails to respond if actually called upon during a reserve event to increase output or reduce load. This lack of penalty exposure is an important distinction between Tier 1 and Tier 2.

Tier 2 resources are those resources that must be dispatched away from their energy profit maximizing dispatch point in order to maintain their reserve capability. Tier 2 resources include generators that would have been producing at their maximum output to maximize their

¹⁸ Note that the term "energy profit maximizing economic dispatch point" is the dispatch point calculated when optimizing for energy only (as opposed to energy and reserves).

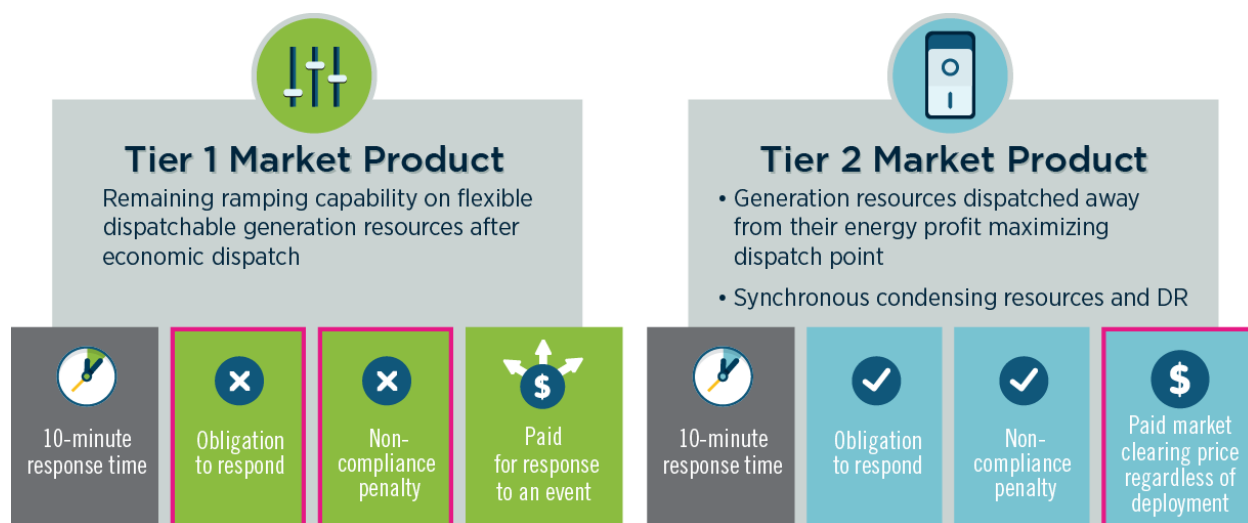
¹⁹ Operating Agreement, Schedule 1 section 1.7.19A(a) ("All on-line nonemergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve to the Office of the Interconnection, as applicable to the capacity resource's capability to provide these services.").

energy profits, but have been requested by PJM to reduce their output to create reserve capability. Tier 2 also includes synchronous condensing resources that incur costs to start from an offline state to synchronize to the grid in order to be prepared to deploy their reserves at PJM's request. Tier 2 resources must submit sell offers to be considered eligible to satisfy the reserve requirements, and if a Tier 2 resource clears but then fails to perform during a reserve event, it is subject to a penalty of a loss of revenue.

The market clearing process assumes that all available Tier 1 reserve capability is free. This reserve capability is counted toward the Synchronized Reserve Requirement first. If the requirement cannot be met solely by Tier 1, Tier 2 resources are cleared to meet the remainder of the requirement. If Tier 2 resources are assigned and there is a non-zero clearing price, only Tier 2 resources are paid the clearing price, as they are the only resources that have an obligation to respond, even though Tier 1 resources are providing the exact same product and are relied upon to respond by the system operator.

The following diagram summarizes the distinction between Tier 1 and Tier 2 resources.

Figure 1. Synchronized Reserve Market Product Descriptions



The Tier 1/Tier 2 construct was a component of PJM's August 29, 2002 proposal to implement a "spinning" reserve market (now referred to as Synchronized Reserve).²⁰ The Commission accepted PJM's proposal (inclusive of the bifurcation of Synchronized Reserve into Tier 1 and Tier 2) on the basis that it "will allow companies to self-provide spinning reserves, provide more transparent prices, and provide greater incentive for companies to supply spinning reserve."²¹ For the reasons described below, the Tier 1/Tier 2 construct for Synchronized Reserve no longer serves the supply incentive or price transparency objectives that the Commission identified in 2002, and is no longer just and reasonable. PJM notes that its Tier 1/Tier 2 construct is unique among RTOs/Independent System Operators ("ISOs"), and accordingly the Commission would not be required to impose any findings regarding the unjust and unreasonable nature of this PJM-specific structure onto the unique reserve market constructs of other RTOs/ISOs.

2. *PJM's Tier 1/Tier 2 construct is unjust and unreasonable because it does not properly incentivize supply and response of synchronized reserves.*

The Tier 1/Tier 2 construct does not properly incentivize the supply and response of Synchronized Reserves in PJM. Tier 1 resources currently play an outsized role in meeting PJM's Synchronized Reserve Requirement. For instance, in 2017, on average, over 1,100 MW of the approximately 1,500 MW Synchronized Reserve Requirement was assigned to Tier 1 resources.²² In addition, for approximately one-third of the hours of 2017, PJM's *entire*

²⁰ *PJM Interconnection, L.L.C.*, Tariff Filing, Docket No. ER02-2519-000 (Aug. 29, 2002) ("PJM ER02-2519 Filing").

²¹ *PJM Interconnection, L.L.C.*, 101 FERC ¶ 61,115, at P 13 (2002).

²² See Monitoring Analytics, LLC, *State of the Market Report for PJM*, at 444 (Table 10-6) (Mar. 8, 2018), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017-som-pjm-volume2.pdf ("2017 State of the Market Report"). This outsized role of Tier 1 increased in 2018, where on average, 1,728.7 MW of Tier 1 was available fully satisfying the synchronized reserve requirement in 50.3 percent of intervals. See Monitoring Analytics, LLC, *State of the Market Report for PJM*, at 455-56 (Mar. 14, 2019),

Synchronized Reserve Requirement was assigned *solely* by Tier 1 reserves. However, as referenced above, Tier 1 resources have no obligation to respond to a Synchronized Reserve event, and face no penalties if they fail to respond. As a result, the response rate of Tier 1 resources is unacceptably low.

To illustrate this point, in its 2016 State of the Market Report,²³ the Independent Market Monitor for PJM (“IMM”) presented data showing that Tier 1 resources had an average response rate of 75.1 percent for the year’s total Synchronized Reserve events that were ten minutes or longer. Included in this average were two events where the response rates for Tier 1 resources were 66.8 percent and 60.2 percent.²⁴ By contrast, Tier 2 resources which, as referenced above, are obligated to respond to a Synchronized Reserve event, are always paid for their cleared MWs when there is a non-zero reserve clearing price, and face a penalty if they fail to respond, had an average response rate of 85.5 percent.

Figure 2. 2016 Response Rates for Tier 1/Tier 2 Resources.

Spin Event (Day, Time)	Duration (Minutes)	Tier 1 Estimate (MW Adj by DGP)	Tier 1 Response (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	Tier 1 Response Percent	Tier 2 Response Percent
Jan 18, 2016 17:58	12	861.0	733.5	616.7	508.8	107.9	85.2%	82.5%
Feb 8, 2016 15:05	10	1,750.2	1,338.2	228.4	200.1	28.3	76.5%	87.6%
Apr 14, 2016 20:09	10	1,182.8	1,000.6	346.3	304.8	41.5	84.6%	88.0%
Jul 28, 2016 13:28	15	649.4	500.4	822.9	655.8	167.1	77.1%	79.7%
Nov 4, 2016 17:13	11	744.5	497.1	758.0	709.2	48.8	66.8%	93.6%
Dec 31, 2016 05:10	12	971.2	585.0	594.4	485.7	108.7	60.2%	81.7%
2016 Average	11.7	1,026.5	775.8	561.1	477.4	83.7	75.1%	85.5%

https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf (“2018 State of the Market Report”).

²³ See Monitoring Analytics, LLC, *State of the Market Report for PJM*, at 416 (Table 10-20) (Mar. 9, 2017), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-volume2.pdf.

²⁴ Note that Tier 1 resources that fail to respond are not required to articulate to PJM any specific reason as to why they failed to respond.

In its 2017 State of the Market Report,²⁵ the IMM found that the average response rate of Tier 1 resources across all of the year's Synchronized Reserve events that were 10 minutes or longer had decreased to 60.1 percent. In that year, the IMM recorded Tier 1 response rates for three individual events at 67.7 percent, 59.3 percent, and a disturbing 14.3 percent. By contrast, Tier 2 had an average response rate of 87.6 percent, including three individual events where Tier 2 response was over 90 percent.

Figure 3. 2017 Response Rates for Tier 1/Tier 2 Resources.

Spin Event (Day, Time)	Duration (Minutes)	Tier 1 Estimate (MW Adj by DGP)	Tier 1 Response (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	Tier 1 Response Percent	Tier 2 Response Percent
Mar 23, 2017 06:48	24	926.8	549.6	742.8	559.1	183.7	59.3%	75.3%
Apr 8, 2017 11:53	10	1,222.6	827.2	879.3	828.7	50.6	67.7%	94.2%
May 8, 2017 04:18	10	1,325.6	976.3	335.1	298.5	36.6	73.6%	89.1%
Jun 8, 2017 03:39	10	974.4	726.7	575.7	522.4	53.3	74.6%	90.7%
Sep 4, 2017 20:03	15	476.3	68.1	601.0	563.8	37.2	14.3%	93.8%
Sep 21, 2017 14:15	16	305.8	217.4	1,253.9	1,037.3	216.6	71.1%	82.7%
2017 Average	14.2	871.9	560.9	731.3	635.0	96.3	60.1%	87.6%

In its 2018 State of the Market Report,²⁶ the IMM recorded yet another year of poor performance for Tier 1 resources, finding the Tier 1 response rate in 2018 to be 63.3 percent, including four individual events where the Tier 1 response rates were 68.2 percent, 66.9 percent, 55.6 percent, and 26.9 percent.

Figure 4. 2018 Response Rates for Tier 1/Tier 2 Resources

Spin Event (Day, EPT Time)	Duration (Minutes)	Tier 1 Estimate (MW Adj by DGP)	Tier 1 Response (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	Tier 1 Response Percent	Tier 2 Response Percent
Jan 3, 2018 03:00	13	1,896.7	509.9	112.6	57.6	55.0	26.9%	51.2%
Apr 12, 2018 17:28	10	1,063.3	591.2	464.6	372.5	92.1	55.6%	80.2%
Jun 30, 2018 09:46	11	2,710.1	2,086.2	71.6	56.8	14.8	77.0%	79.3%
Jul 10, 2018 15:45	12	784.3	524.9	494.6	308.8	185.8	66.9%	62.4%
Aug 12, 2018 11:06	11	1,824.5	1,390.4	274.5	229.8	44.7	76.2%	83.7%
Sep 30, 2018 11:29	11	1,430.9	976.4	231.2	216.9	14.3	68.2%	93.8%
Oct 30, 2018 06:40	11	239.7	215.9	607.7	431.5	176.2	90.1%	71.0%
2018 Average	11	1,421.4	899.3	322.4	239.1	83.3	63.3%	74.2%

²⁵ See 2017 State of the Market Report at 460.

²⁶ See 2018 State of the Market Report at 473.

This unacceptably low response rate for Tier 1 resources, as compared with the response rate for Tier 2, is strong evidence of an incentive problem in the PJM market, and unnecessarily increases risk to reliability during a Synchronized Reserve event, given the outsized role that Tier 1 resources play in meeting PJM’s reserve requirements.

To this point, Commission staff previously has recognized the importance of proper pricing to provide correct incentives in its October 2014 paper entitled “Staff Analysis of Shortage Pricing in RTO and ISO Markets” as part of the Commission’s Price Formation proceeding in Docket No. AD14-14-000, noting on the very first page that:

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. Reducing such inefficiencies may lead to more reliable and more economic electric service to consumers.²⁷

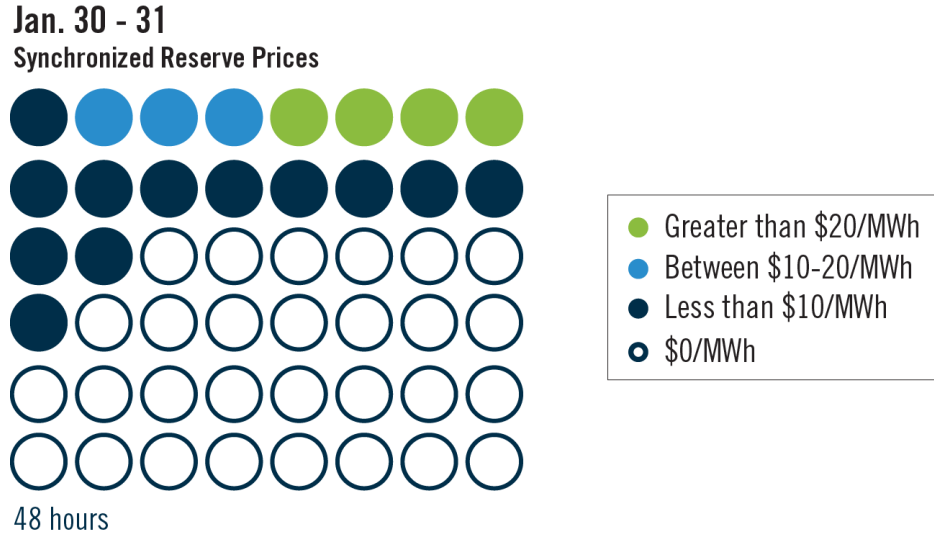
In that same vein, Dr. Hogan and Dr. Pope maintain that “[t]he accuracy of the real-time price signal, in terms of sending a high price when the supply (i.e., energy plus reserves) is constrained, or a low price during times of abundant supply, is a lynchpin of efficient electricity market design.”²⁸ Yet, simply, Synchronized Reserves are not appropriately valued in PJM’s market today. While this is true on any given day, it is most problematic that the system fails to value reserves when the system is most stressed. The most recent example is depicted in Figure 5 concerning the extremely cold conditions PJM experienced in this past January 2019, wherein prices were \$0/MWh for 29 hours of the 48-hour period, and were less than (and mostly significantly less than) \$10/MWh for 41 hours of the 48-hour period.²⁹

²⁷ 2014 FERC Staff Shortage Pricing Report at 1.

²⁸ Hogan & Pope PJM ORDC Report at 5.

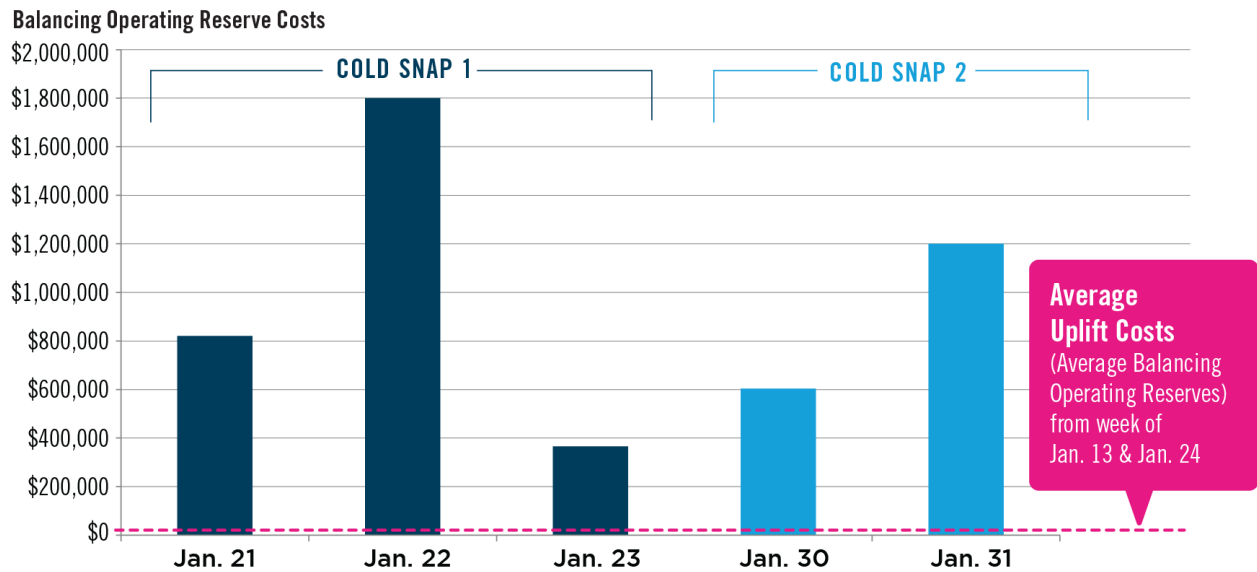
²⁹ Hours less than \$10 included two at \$0.08, one at \$0.63, one at \$0.69 and one at \$1.88 10-minute, non-synchronized reserve prices were \$0 for 46 of the 48 hours.

Figure 5.



Out-of-market actions by PJM dispatchers to ensure adequate reserves during these stressed conditions led to a spike in uplift as shown in Figure 6.

Figure 6.



Given the structural discrepancies in the incentives for Tier 1 and Tier 2 resources, and the corresponding divergence in documented operational performance, the Tier1/Tier 2 construct no longer meets the supply incentive objectives that the Commission identified in 2002 and, accordingly, is no longer just and reasonable.

3. *The Tier 1/Tier 2 construct is unjust and unreasonable because it impedes price transparency.*

The Tier 1/Tier 2 construct harms overall price transparency in the PJM market. Because the Tier 1 product is voluntary, only compensated in response to a Synchronized Reserve Event, and has an inherently inconsistent response rate, it is difficult for PJM to accurately estimate the amount of Tier 1 resources on the PJM system at any given time, and the amount that will actually respond to a Synchronized Reserve Event. As described in Mr. Pilon's Affidavit, despite the fact that PJM has taken multiple steps over the years to better align its Tier 1 estimates to be more reflective of expected *actual* resource response,³⁰ the response rate of Tier 1 resources continues to be unacceptably low.

As a result, PJM system operators frequently take actions to account for the response deficiencies of Tier 1 resources, such as: (i) manually assigning Tier 2 reserves intra hour; (ii) reducing the hour-ahead Tier 1 estimate via a "Tier 1 bias" that must be manually entered in to the hour-ahead reserve procurement tool (the Ancillary Services Optimizer, or "ASO"); and (iii) planning to meet the contingency recovery requirements by using Non-Synchronized (Primary) Reserves.³¹ These actions are rational given the low actual response of Tier 1 resources relative to what is estimated, as evidenced in Figures 2–4 above. However, they are nonetheless manual and/or out-of-market actions that can result in uplift, are fundamentally at odds with the objectives of market price transparency, and can have a suppressive effect on reserve prices because the explicit demand for Tier 2 reserves that are obligated to respond is not reflected in the market.

³⁰ Pilon Aff. ¶¶ 24-26.

³¹ Pilon Aff. ¶ 26.

Additionally, the confidence level in Tier 1 reserves differs by each system operator and each scenario.³² This can create inconsistent operator interventions into the market. In most circumstances, operators over-respond and add more Tier 2 into the market than the demand for Synchronized Reserves reflects, thereby suppressing prices and creating uplift.³³

The Commission has explained that “as a general matter, market-based solutions are preferable to out-of-market solutions,”³⁴ and, as discussed in the next section, previously found the use of out-of-market operator actions at the expense of transparent market outcomes to be unjust and unreasonable in the specific context of reserve markets.

B. PJM’s Current Operating Reserve Demand Curve Is Unjust and Unreasonable.

1. Overview of the current ORDC

In PJM, real-time reserve markets are cleared using ORDCs. Under the current market rules, these ORDCs take the general shape of a vertical curve with step functions. When the reserve requirement cannot be met, the reserve shortage is priced using the “penalty factor” specified in the applicable ORDC. Stated simply, under today’s model, the penalty factor is used to determine the price for being unable to meet the MRR. This price is intended to send a signal to market participants that, as the reserve market clearing price reaches the penalty factor, a reserve shortage may occur. Because PJM co-optimizes energy and reserves, the penalty factor is also included in the calculation of the energy price such that when the system is unable to meet its reserve requirement, energy prices are intuitively high.

More broadly, ORDCs administratively set the amount of reserves to clear, define the limit on the cost the market is willing to incur to substitute reserves for energy, and functionally

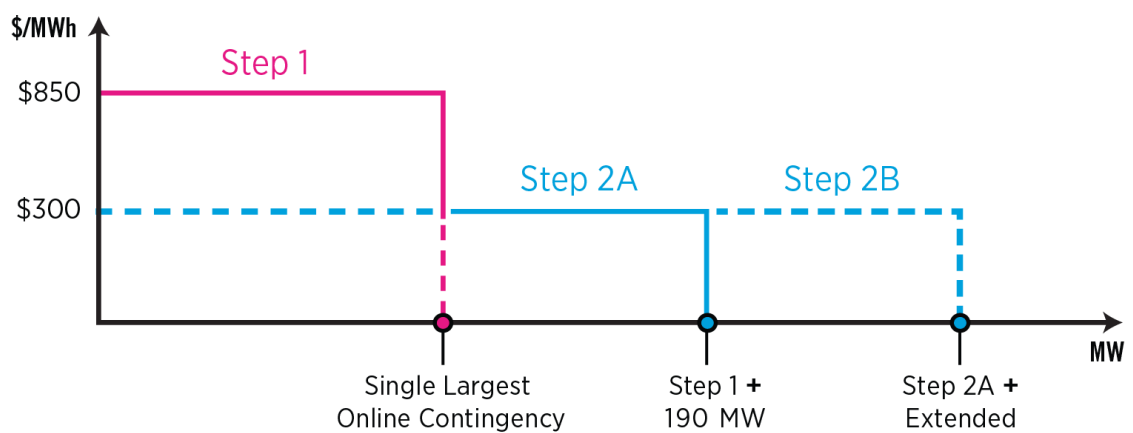
³² Piloni Aff. ¶¶ 9, 11.

³³ See Keech Aff. ¶¶ 50-54.

³⁴ *ISO New England Inc.*, 144 FERC ¶ 61,204, at P 42 (2013), *reh’g denied*, *Transcanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1 (2015).

act as a “cap” on the market clearing price to clearly indicate reserve shortages.³⁵ Although always present in market clearing, PJM’s current ORDCs only explicitly affect price when not enough reserves are available at or below the MRR or are at a modest level (190 MW) beyond the MRR. PJM’s ORDCs use penalty factors to represent customers’ theoretical maximum willingness to pay for varying quantities of reserves, and ultimately are used in the calculation of energy and reserve prices during shortage conditions for both Synchronized and Primary (i.e., Non-Synchronized) Reserves. The current demand curve for Synchronized Reserve is shown as follows.

Figure 7. Current Synchronized Reserve Demand Curve



The Synchronized Reserve megawatts demanded in the red portion of the curve, labeled Step 1, are determined by the real-time megawatt output of the single largest online contingency. This quantity criterion is the MRR and has been in place since 2012, when shortage pricing was implemented.³⁶ The penalty factor of Step 1, \$850/MWh, is based on analysis of the out-of-market make-whole payments made for reserves from an operating event in 2007.³⁷ The blue

³⁵ Depending on the modeling of reserve products and sub-zones, the actual cap on a reserve product in a location may be the sum of multiple penalty factors due to the nesting of products and regions.

³⁶ *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057 (2012) (“Order No. 719 Compliance Order”).

³⁷ *Id.* at PP 63, 78.

portions of the Synchronized Reserve demand curve, Steps 2A and 2B, were both added more recently (in 2017 and 2015, respectively).³⁸ The purpose of Step 2A was to add a smaller step on the curve to avoid system volatility due to large swings in price for small changes in reserve amounts that would have occurred with just Step 1.³⁹ PJM implemented this change to the ORDC in response to Order No. 825 which required PJM and others to price all reserve shortages, even those that are transient in nature. Step 2B was added as a result of a package that was approved by PJM members that originated in the Energy and Reserve Pricing and Interchange Volatility special sessions of the Market Implementation Committee. The purpose of this optional step was to create the ability to extend the reserve requirement when PJM operators took actions to schedule additional reserves during conservative operations.⁴⁰

PJM's current ORDCs are unjust and unreasonable for two primary reasons. First, the current ORDCs' penalty factor levels are inadequate, as they do not capture all actions PJM operators will take to meet PJM's MRRs that are required to maintain compliance with the North American Electric Reliability Corporation ("NERC") reliability standards, thereby forcing any action at a cost above the penalty factor to be taken out-of-market and not reflected in prices. According to Dr. Hogan and Dr. Pope: "These actions skew and depress market price signals."⁴¹ This reality stands in opposition to the Commission's articulated policy objectives regarding market transparency for shortage pricing. Second, while PJM's current ORDCs acknowledge the

³⁸ *PJM Interconnection, L.L.C.*, Letter Order, Revisions to PJM's Operating Reserve Demand Curves, Docket No. ER17-1590-000 (Jul. 7, 2017); *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,017 (2015).

³⁹ Letter Order, Revisions to PJM's Operating Reserve Demand Curves, Docket No. ER17-1590-000 (Jul. 7, 2017).

⁴⁰ This extension has a narrow scope, and has never been invoked. It is intended only for use in Conservative Operations, which is defined in PJM Manual 13 as a state of operations triggered by a weather, environmental, or physical or cyber security event. See PJM, *Manual 13: Emergency Operations*, § 3.2 (rev. 68, Jan. 1, 2019), <https://www.pjm.com/~media/documents/manuals/m13.ashx> ("Manual 13"), section 3.2. That reserve extension is just one of an array of measures PJM lists in Manual 13 for use when facing a triggering event. This extension was not proposed to address the dispatcher schedule biasing actions (or other operator out-of-market actions) as discussed in section II.B.3 of this transmittal.

⁴¹ Hogan & Pope PJM ORDC Report at 12.

value of committing reserves beyond the MRR, that added step (permitting PJM to incur up to a \$300/MWh for up to 190 MWh of added reserves) is limited, and does not attempt to estimate the value that reserves beyond the added step can provide in reducing the risk of falling below the MRR in real-time. In particular, the current rules do not adequately recognize the actions PJM market operators take regularly to reduce the uncertainty of falling below the MRR. This fails to acknowledge the value to reliability and price stability that such excess capability provides—two features that the Commission specifically identified in its prior rulings on PJM’s capacity market. Each of these is described below.

PJM notes that it is unique in that it carries a much smaller amount of reserve in proportion to total system load than other ISOs/RTOs. While carrying lower reserves is a major cost savings to load and a consequence of a larger pool like PJM, the quantity must still be sufficient to support reliability while providing proper pricing and incentives. Other ISOs/RTOs have minimum reserve requirements in the range of 1,000-2,000 MW like PJM, but system load is much less than PJM’s system load. For instance, approximations utilizing peak load show that in PJM’s the Synchronized Reserve Requirement is on average approximately 1,600 MW out of approximately 150,000 MW (1.05 percent) and Primary Reserves is on average approximately 2,300 MW out of approximately 150,000 MW (1.51 percent). In ISO New England Inc. (“ISO-NE”), the 10-Minute Total Reserve requirement (comparable to PJM Primary Reserve) is approximately 1,600 MW out of 24,000 MW (6.7 percent).⁴² And in the New York Independent System Operator, Inc. (“NYISO”), Total Synchronous Reserves (comparable to PJM Synchronized Reserves) is 655 MW out of approximately 30,000 MW (2.2%) and Total 10

⁴² The ISO-NE peak load figure can be found in the ISO-NE 2017 Annual Markets Report at page 5. ISO New England Inc. Internal Market Monitor, *2017 Annual Markets Report*, at 5 (May 17, 2018), <https://www.iso-ne.com/static-assets/documents/2018/05/2017-annual-markets-report.pdf>. The reserve requirements can be found on the ISO-NE website *Hourly Reserve Requirements*, ISO New England Inc., <https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/ancillary-hourly-rr> (last visited Mar. 29, 2019).

Minute Reserves (comparable to PJM Primary Reserves) is 1,310 MW out of approximately 30,000 MW (4.4%).⁴³ Recognizing that PJM often carries reserves in excess of the requirement, comparisons of the average megawatts of reserve carried by PJM still demonstrate that PJM systematically carries less reserves (as a percentage of peak load) than other ISOs/RTOs. In 2018, PJM carried on average 2,139 MW of Synchronized Reserve (1.43%) and 3,282 MW of Primary Reserve (2.19%). With PJM's relatively small margin of reserves, the probability of falling below the minimum requirements is greater in PJM. PJM's proposal recognizes this probability. The simulations discussed by Mr. Keech demonstrate an increase in the average amount of reserves that would be carried under this proposal. The average Synchronized Reserves carried increased to 3,168 MW (2.11% of peak load) while the average Primary Reserves carried increased to 3,846 MW (2.56% of peak load). Even with the expected increases in reserve quantities with this proposal, PJM will still be far below that of other RTOs relative to system load.

2. *The current Reserve Penalty Factor levels are inadequate as they do not fully reflect in clearing prices the incremental cost of resources that PJM needs to meet MRRs.*

When PJM implemented the current ORDCs in 2012, the demand curves were only a single step at the existing \$850/MWh penalty factor. At that time, the energy offer cap was \$1,000/MWh. PJM proposed \$850/MWh as the final penalty factor to be used in a phased transition plan to implement shortage pricing in a manner that was compliant with Order

⁴³ The NYISO peak load figure can be found in the 2017 State of the Market Report at page 8. Potomac Economics, *2017 State of the Market Report for the New York ISO Markets*, at 8 (May 2018), https://www.potomaceconomics.com/wp-content/uploads/2018/06/NYISO-2017-SOM-Report-5-07-2018_final.pdf. The reserve requirements can be found on the NYISO website. *NYISO Locational Reserve Requirements*, New York Independent System Operator, Inc., https://www.nyiso.com/documents/20142/3694424/nyiso_locational_reserve_reqmts.pdf/ab6e7fb9-0d5b-a565-bf3e-a3af59004672.

No. 719.⁴⁴ As stated previously, this number was derived based on the average out-of-market payments to resources that were providing reserves during a shortage event in 2007. Although the \$850/MWh penalty factor was filed in compliance with Order No. 719,⁴⁵ it, along with the transition plan to escalate penalty factors over a number of years, represented a compromise position for PJM that attempted to strike a balance between a penalty factor level that would accommodate “most” operating conditions and allaying stakeholder concerns that prices would be “too high.”

At that time, PJM and stakeholders discussed the primary side effect of setting the penalty factor too low—false positives for shortage pricing. Also referred to as “economic shortages,” in these scenarios the physical capacity is available to meet PJM’s energy and reserve needs at costs in excess of \$850/MWh, but the penalty factor limits the ability for the Security Constrained Economic Dispatch (“SCED”) engines to take those actions and for the prices to reflect that such actions were taken. While that potential existed at the time the \$850/MWh penalty factor was proposed, given that the ultimate offer cap was \$1,000/MWh (which is in close proximity to the \$850/MWh penalty factor), the probability of an economic shortage was relatively slim, and therefore PJM was willing to compromise on its position.

Several rules in the market have since changed, thereby requiring PJM to reexamine the previously-established penalty factor level, and ultimately proposing to increase it. With respect to PJM’s current design, Dr. Hogan and Dr. Pope explain: “Implementation of the existing design, especially given changing operating conditions, yields energy and operating reserve prices in PJM that do not align with economic principles. The prices of incremental reserves and

⁴⁴ Order No. 719 Compliance Order at P 62.

⁴⁵ *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071, (2008), *order on reh’g*, Order No. 719-A, 128 FERC ¶ 61,059, (2009), *order on reh’g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

energy can deviate from incremental cost and are not consistent with the implications of first principles for determining the value of operating reserves when supply is constrained.”⁴⁶ The primary driver for PJM’s decision to modify its penalty factor is that the structure of offers has changed since 2012. In November 2016, Order No. 831 established an ultimate cap on price-setting offers of up-to \$2,000/MWh.⁴⁷ The Commission did, of course, require such offers to be cost-justified, but once were justified, operators utilizing those resources would be calling on an asset which has an offer value ranging potentially up to \$2,000/MWh. This change on its own warrants a review of the penalty factor, as it results in transactions (generation offers, demand response offers, and import transactions) with cost-justified offers up to \$2,000/MWh being dispatched to maintain reserves under certain conditions.

If these offers set the Locational Marginal Prices (“LMP”) (and the intent is to have them do so if they are needed to maintain reliability), it will significantly increase the opportunity cost incurred by resources that are re-dispatched away from their profit maximizing output level to maintain reserves. In order to permit these resources to set the energy prices as they should, and maintain the required level of reserves, the penalty factor must be increased to ensure that all resources available to provide reserves are fully utilized prior to going short reserves. For example, consider a scenario where PJM has deployed demand response with an energy offer of \$1,800/MWh to maintain its reserve requirement and the resource sets the energy price at that level. If a resource exists with an energy offer of \$600/MWh that could be re-dispatched to provide reserves, it would incur a \$1,200/MWh lost opportunity cost if it were assigned reserves.

⁴⁶ Hogan & Pope PJM ORDC Report at 3.

⁴⁷ *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (2016), *order on reh’g & clarification*, Order No. 831-A, 161 FERC ¶ 61,156 (2017), *amended by* 165 FERC ¶ 61,136 (2018) (“Order No. 831”). Also, note that the current strike prices for demand response were established in a May 2014 order, after the establishment of the \$850/MWh penalty factor. See *PJM Interconnection, L.L.C.*, 147 FERC ¶ 61,103, at P 112 (2014).

Under the current penalty factor of \$850/MWh, that resource would not be re-dispatched by the SCED engine to provide reserves because the cost to do so, \$1,200/MWh, exceeds the penalty factor of \$850/MWh. Absent the ability to meet the requirement at a cost less than \$850/MWh, the system would go into shortage pricing despite the capacity being physically available to meet the reserve requirement (a false positive). In this scenario, the prices will not reflect the operating state of the system because the system is not physically short.

To avoid a physical shortage, system operators will manually dispatch the \$600/MWh resource to maintain the needed reserves and the resource will be paid through uplift.⁴⁸ As Mr. Keech explains, “There are two possible outcomes from this: (1) system operators manually assign this unit reserves, reserve and energy prices do not reflect actual system conditions, and it is paid through uplift; or (2) there is an economic shortage because the physical capacity was available to meet the requirement but the willingness to pay for reserves (Reserve Penalty Factor) was set too low. Both are undesirable and reflect the need to increase the Penalty Factor.”⁴⁹ Simply, the market prices do not transparently reflect the operator actions—the operator was required to take an out-of-market action to maintain reserves, and that action resulted in uplift and associated cost-shifting.

This operational reality runs counter to the Commission’s prior guidance on transparency for shortage pricing in organized wholesale markets, and specifically to the basis upon which the Commission approved PJM’s current ORDCs and associated penalty factors. In Order No. 719, the Commission found that rules that “do not allow for prices to rise sufficiently during an operating reserve shortage to allow supply to meet demand are unjust, unreasonable, and may be unduly discriminatory,” because they “may not produce prices that accurately reflect the value of

⁴⁸ See Keech Aff. ¶ 11.

⁴⁹ *Id.*

energy and, by failing to do so, may harm reliability, inhibit demand response, deter entry of demand response and generation resources, and thwart innovation.”⁵⁰ In response to concerns raised by the PJM Power Providers group regarding shortage pricing mechanisms and the need for prices to reflect actual system operation, the Commission stated that “[w]e share PJM Power Providers’ concern about out-of-merit order generation, such as the example they cite, and it being reimbursed through uplift charges.”⁵¹ The Commission further noted that “[a] market works more efficiently when all decisions of the system operator that affect costs, e.g., running peaking units, are reflected in market prices rather than in uplift charges,” and stated that “[w]e encourage all RTOs and ISOs to consider this when evaluating their existing shortage pricing rules or developing new ones.”⁵²

Similarly, in its order on PJM’s Order No. 719 compliance filing, the Commission specified that “the costs of resources procured to alleviate shortages should be reflected in transparent market prices whenever possible” and that “[p]ayments made only to individual resources and recovered in uplift fail to send clear market signals.”⁵³ The Commission noted that “PJM is required to schedule sufficient contingency reserves to satisfy [ReliabilityFirst Corporation] requirements” and accordingly “[i]t is appropriate that PJM be able to reflect the costs of these reserves in a transparent market clearing price.”⁵⁴

Applying these principles, the Commission in the Order No. 719 Compliance Order reviewed specific evidence and analysis provided by PJM, and concluded that market prices for reserves had failed to accurately reflect the true value of those reserves during shortages.

⁵⁰ Order No. 719, 125 FERC ¶ 61,071, at P 192.

⁵¹ *Id.* at P 207.

⁵² *Id.*

⁵³ Order No. 719 Compliance Order at P 63.

⁵⁴ *Id.* at P 98.

PJM has identified seven events occurring during 28 hours over the previous five years when reserve shortage conditions have been experienced within the PJM region. During these shortage events, synchronized reserve market clearing prices were consistently low, sometimes as low as \$ 0 per MWh, while energy prices ranged between \$ 300 per MWh to just over \$ 1,000 per MWh. However, during most of these shortage events, there were sizable out-of-market, resource-specific opportunity cost payments made to resources that were held back from energy production to provide reserves, including payments as high as \$ 923 per MWh during the August 8, 2007 event. This evidence demonstrates that market prices for reserves have not reflected the cost and value of providing reserves during these periods.⁵⁵

We find convincing PJM's analysis of reserve shortage events showing relatively low, or even zero value, clearing prices for synchronized reserves in the face of a reserve shortage. For example, on August 2, 2006, PJM recorded its all-time peak load of 145,000 MW and the entire RTO was in a shortage of total 10-minute reserves. However, the synchronized reserve market clearing price was zero throughout this reserve shortage event. The zero price for reserves occurred in the presence of high energy prices and a deployment of emergency demand response resources. For the above reasons, we find that this price formation during a primary reserve shortage is not consistent with system or dispatch needs.⁵⁶

The most effective way to avoid the ill-effects associated with economic shortages and achieve the Commission's goal of price transparency is to set the penalty factor high enough to reflect the actions the operator will take to maintain reserves. In Order No. 831, the Commission established \$2,000/MWh as the maximum level at which an offer can be eligible to set the LMP. This level is critically important because it also establishes the maximum reasonable opportunity cost that a resource may incur when providing reserves with an LMP of \$2,000/MWh. The term "reasonable" is used in this context because the marginal cost of supply is only one component of the LMP. In addition to that component, LMP includes congestion and losses which may

⁵⁵ *Id.*

⁵⁶ *Id.* at P 71.

increase (or decrease) the LMP relative to the marginal energy offer. The effects of these components can vary greatly by node across the system and over time, yet the ORDC, by definition, must capture the cost of actions to maintain reserves across a broad area of the footprint over which the reserve requirement is defined.⁵⁷ Thus, as discussed in Section III.B below, under current PJM market rules, \$2,000/MWh is the lowest reasonable level at which the penalty factor can be set and still be consistent with actions that system operators are required to take to maintain reserves.

Absent increasing the penalty factor to \$2,000/MWh as proposed below, system operators will be required to continue procuring reserves in the future at costs above \$850/MWh outside the market, creating a distortion in the market that results in uplift. Dr. Hogan and Dr. Pope noted this in saying “[b]ecause the penalty factor is lower than the cost of these actions, it will not provide a market price signal to call forth voluntary provision of additional reserves at prices lower than the cost of the mandatory emergency actions.”⁵⁸ This, they say, can lead to “suppress[ed] energy and reserve prices and increase uplift costs.”⁵⁹ In sum, the current \$850/MWh penalty factor is inconsistent with PJM’s system operations and incompatible with the Commission’s goal of price transparency, and is therefore unjust and unreasonable.

3. *PJM’s current ORDCs acknowledge the value of reserves above the MRR to a limited point, but unreasonably fail to account for the uncertainties that PJM operators currently must address to maintain system balance and adequate reserves.*

As explained in Mr. Pilog’s affidavit, PJM must maintain reserves to respond to the single largest contingency on the system at any given time, in compliance with NERC reliability

⁵⁷ See Hogan & Pope PJM ORDC Report at 14 (“Operating reserves are a system requirement. They are a product that provides reliability simultaneously to all users of the system.”).

⁵⁸ *Id.* at 3.

⁵⁹ *Id.*

standards.⁶⁰ Pursuant to its reliability obligations, PJM must not only maintain system balance and all reserve requirements, but must also conduct prospective forecasting and planning activities on an ongoing basis to ensure that system balance and reserve requirements are maintained throughout the operating day.⁶¹ PJM uses automated tools and support staff to produce applicable forecasts and ensure that these forecasts are as accurate as possible.⁶²

However, as with all forecasts, some level of error is always present, because PJM does not have perfect vision into the future. Factors such as *actual* load, *actual* interchange, and the *actual* performance/availability of generation resources can and often do deviate from their forecasted quantities, despite PJM's efforts to achieve maximal forecasting accuracy. As a result, PJM dispatchers will brace against the potential for forecast error by "biasing" the cases produced by Intermediate Term ("IT") SCED, thereby ensuring that adequate generation is online and available for the Real-time ("RT") SCED engine to use to meet PJM's demand and reserve requirements.⁶³ As Mr. Pilon explains:

This bias is a catch-all value to account for all possible errors in the forecasts. Its effect is to increase (or decrease) the amount of net demand that the IT SCED solution will optimize for and therefore recommend that additional (or reduced) resources be committed. For example, during a morning load pick-up when demand is increasing rapidly, the dispatcher may bias the cases by 2,000-3,000 [MWs] to account for faster-than-expected load, lower-than-expected generation, and generators that are slow to

⁶⁰ Pilon Aff. ¶ 21.

⁶¹ *Id.* ¶¶ 5-7.

⁶² *Id.* ¶ 6.

⁶³ *Id.* ¶¶ 8-11. Note that for the same reason that PJM's forecasts are not 100 percent accurate—PJM does not have perfect vision into the future—PJM's IT SCED biasing is similarly not 100 percent accurate. In the event that the projected forecast error turns out to be smaller than anticipated, the potential exists for PJM to have scheduled additional generation that is not ultimately needed by the RT SCED engine. As discussed below, and as Mr. Keech explains, this could lead to price suppression and, ultimately, uplift. See Keech Aff. ¶ 40.

ramp-up. Use of a bias, and the amount of the bias, are based on the dispatcher's training, experience, and judgement.⁶⁴

This intentional biasing of generator scheduling is essential to maintain reliability under the current market construct.⁶⁵

In certain instances, PJM dispatchers will also take out-of-market actions to commit additional generating reserves manually. This may occur for conditions that IT SCED biasing is not directly able to account for, such as the need for longer lead generation that must be committed prior to the IT SCED 2-hour window, or if there is a locational need for the reserves due to major transmission constraints.⁶⁶

Neither of these two categories of operator actions, biasing and out-of-market commitments, which are directed to the essential role of maintaining system balance and required reserves, are presently incorporated into the design of PJM's current ORDCs. Currently, PJM has a second step (Step 2A) on its demand curves that is 190 MW at a penalty factor of \$300/MWh. While Step 2A provides some metric by which to value reserves in excess of the MRR, its original intent was to act as a buffer to protect against price swings, and not to explicitly value reserves beyond the minimum requirement.⁶⁷ Additionally, the length and price associated with this step are not consistent with the current magnitude of the real-time uncertainties in the PJM market. For example, the length of Step 2A is 190 MW, but the average

⁶⁴ Pilon Aff. ¶ 9.

⁶⁵ Pilon Aff. ¶ 9.

⁶⁶ Pilon Aff. ¶¶ 18-20.

⁶⁷ Step 2A was implemented in 2017, in response to Order No. 825. In that order, the Commission required that RTOs/ISOs to price all transient shortages regardless of duration. Order No. 825, 155 FERC ¶ 61,276, at P 162. This order was not consistent with PJM's practice of only pricing a reserve shortage if it was expected to persist for at least 30 minutes. In addition to changes to technical software, PJM also filed changes to its ORDCs under Section 205 to implement Step 2A on the ORDC. The calculus behind Step 2A is far less rigorous than what is provided herein to support the proposed ORDCs. The 190 MW width of Step 2A is based on the mean level of reserve shortage experienced over the study period plus one standard deviation. The \$300/MWh price associated with that step was based on an analysis of generator offers submitted at that time that might be called online to help mitigate a potential shortage of the \$850/MWh step.

wind forecast error *alone* during the early hours in winter time (period 2015-2017) is around 160 MW.⁶⁸ If this average wind uncertainty were to materialize, then 160 MW of the additional 190 MW reserves procured would already be taken up by this single uncertainty.⁶⁹ In addition, as currently structured, PJM's ORDCs contain "vertical" curves that prohibit PJM from explicitly scheduling the flexibility that is needed to accommodate legitimate forecasting uncertainties beyond the requirement expressed in Step 2A of the demand curve. This mutes investment incentives for flexible resources in PJM that will be needed to operate reliably given the ever-growing amount of renewables in PJM.

This limitation on PJM's ORDCs runs counter to sound economic principles. Specifically, as described in the Hogan & Pope PJM ORDC Report, in assessing PJM's current ORDCs, Dr. Hogan and Dr. Pope conclude:

The existing PJM market design includes the basic elements of an ORDC through two levels of penalty factor when operating reserves fall to certain reserve thresholds. But this design is inadequate. It does not recognize the true value of reserves along a continuum derived from the probabilistic representation of the expected need for additional reserves in real-time. Additionally, the maximum penalty price falls short of the cost of actions the PJM system operator currently takes in order to restore operating reserves. This leaves market participants exposed to the impact of out of market decisions which undermines confidence by PJM market participants that the prices in the markets will be the result of competitive market forces.⁷⁰

Both types of actions taken by operators –out of market procurement and biasing—can result in uplift. The former scenario is— a resource that is needed to provide reserves but was scheduled outside of the market engine will be eligible for make whole payments that result in uplift.

⁶⁸ Rocha Garrido Aff. ¶ 20.

⁶⁹ *Id.* Furthermore, in this example, only the average wind forecast error was considered; there is a non-zero chance such wind forecast error is greater than the average, not to mention the fact that there are additional uncertainties.

⁷⁰ Hogan & Pope PJM ORDC Report at 4.

However, the price suppression and related uplift payments necessitated by biasing may not be as obvious. Mr. Keech provides an example in his affidavit.⁷¹ He explains, to the extent additional resources are procured as a result of biasing than are actually needed during the operating interval, such resources will result in excess supply on the system and suppress prices. “In the LMP calculation, the goal is to set the marginal clearing price at the lowest cost to serve the next increment of load. When this problem is solved, the solution is to dispatch up the resources with the low incremental cost [t]his sets the LMP for all resources on the system”⁷² which then leads to a make whole payment (and thus uplift) to be paid to the more expensive resources called on as a result of biasing.

This limitation on PJM’s “vertical” ORDCs, which prohibit PJM from explicitly scheduling the flexibility that is needed to accommodate legitimate forecasting uncertainties beyond the requirement expressed in Step 2A of the demand curve, also runs counter to the Commission’s prior acknowledgement of the value to reliability and price stability that excess capability provides in other contexts. For example, in its 2006 order on PJM’s Reliability Pricing Model (“RPM”) settlement,⁷³ the Commission specifically identified the failure of vertical demand curves in PJM to reflect the incremental value to reliability that capacity beyond the Installed Reserve Margin creates, and approved the use of a downward-sloping demand curve in place of the then-existing vertical demand curve. In particular, the Commission stated that “we agree with PJM that a downward-sloping demand curve provides a better indication of the incremental value of capacity at different capacity levels than the current vertical demand

⁷¹ Keech Aff. ¶¶ 50-53.

⁷² *Id.* ¶ 53.

⁷³ *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006) (“RPM Settlement Order”).

curve.”⁷⁴ The Commission observed that “[u]nder a vertical demand curve, capacity above the Installed Reserve Margin is deemed to have no value,” but nonetheless “[i]ncremental capacity above the Installed Reserve Margin is likely to provide additional reliability benefits, albeit at a declining level.”⁷⁵ The Commission concluded that “[t]his value is reflected in the positive (but declining) prices in the sloped demand curve to the right of the Installed Reserve Margin, but is not reflected in the current capacity market.”⁷⁶

In its rehearing order, the Commission reiterated that “[t]he sloping demand curve is designed to replicate a true market in which incremental amounts of capacity will have gradually declining, but positive, reliability benefits” and that “[t]he current vertical demand curve fails to reflect the value of incremental reliability.”⁷⁷ The Commission also stated that “the vertical demand curve results in extremely volatile pricing, because as long as supply exceeds the required amount, the price falls precipitously, while, when capacity is short, price will rise to the deficiency penalty level.”⁷⁸ The rationale underlying the concerns regarding PJM’s vertical demand curves that the Commission has previously expressed in the capacity market context are also applicable to the vertical demand curves in PJM’s reserve market. PJM’s current ORDCs irrationally prevent PJM from explicitly scheduling the flexibility that is needed to accommodate legitimate forecasting uncertainties beyond the requirement expressed in Step 2A of the demand curve through the market, thereby ignoring the incremental value to reliability and price stability that such reserves provide. As discussed below, these uncertainties are projected to increase in

⁷⁴ *Id.* at P 76.

⁷⁵ *Id.*

⁷⁶ *Id.* Note that this framework is not uniform among all RTOs. For example, in MISO, state rate base serves as the backstop for the incremental generation value that the slope demand curve compensates for in PJM.

⁷⁷ *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at P 99 (2007).

⁷⁸ *Id.*; see also *ISO New England, Inc.*, 153 FERC ¶ 61,338 (2015); *Ny. Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201 (2003).

the future. Accordingly, the Commission should find that PJM's currently-effective ORDCs are unjust and unreasonable.

C. *PJM's Day-Ahead and Real-Time Procurement of Reserves is Out of Alignment and is Unjust and Unreasonable.*

1. *PJM's forward procurement of reserves is inadequate.*

PJM's current market design schedules 30-minute reserves in the day-ahead market and maintains 10-minute reserves in the real-time market. There is no attempt at a forward procurement of 10-minute reserves on a day-ahead basis, despite the clear need for these resources in real-time. Every other ISO/RTO has a methodology to procure the reserve products needed in real-time in advance of the operating day except PJM. Many ISOs/RTOs such as SPP, MISO, NYISO, and California Independent System Operator Corporation ("CAISO") align their reserve products in their day-ahead and real-time markets to ensure that when they schedule supply for the next operating day they do so recognizing their reserve needs. ISO-NE's model elects to procure each reserve product on a more forward basis (several months) to ensure adequate supply for real-time system operations. The lack of a forward procurement of reserves relied on in real-time distinguishes PJM from other ISOs/RTOs in this context.

While PJM generally has procured sufficient 10-minute reserves in the real-time market, uncertainty exists as to whether at any given time sufficient reserves will be available in real-time given the lack of any forward obligation to be available to provide such 10-minute reserve capability. What is more, the lack of a day-ahead market precludes such resources capable of providing 10-minute reserve from being able to lock-in to a forward revenue stream that solidifies the incentive to perform in real-time.

Furthermore, the procurement of these reserves is managed completely in real-time and not considered during the scheduling of the vast majority of all other resources needed for that

Operating Day. As a result, PJM's reserve market design is not functioning to procure 10-minute reserves at the lowest cost because, by looking only at resources available to provide reserves in real-time, PJM ignores longer-lead time resources that may have been available and more cost-effective but needed to be lined up day-ahead. The result is that the real-time reserve commitment almost certainly will not result in the lowest cost solution, relative to a day-ahead procurement. Moreover, in extreme circumstances, relying solely on a real-time procurement could result in under-scheduling the needed reserves for real-time causing unnecessary real-time reserve shortages. Thus, PJM's current practice does not meet the threshold for truly co-optimizing energy and reserves in the resource commitment timeframe and therefore does not minimize the procurement cost of these resources.

2. *PJM's 30-minute Day-ahead Scheduling Reserve is not valued, from a market perspective, in real-time despite its operational value.*

Because there currently is no 30-minute Reserve Requirement in real-time, the 30-minute Day-ahead Scheduling Reserves are not viewed as reserves in the real-time market, and PJM can dispatch such megawatts as energy without concern for maintaining any real-time reserve requirement. Thus, by not maintaining a 30-minute reserve product in real-time, the market fails to recognize any value that product may have in maintaining real-time operations. Indeed, as Mr. Pilon explains PJM “maintains a calculation that estimates real-time 30-minute reserves, for situational awareness purposes.”⁷⁹ But given PJM's only current 30-minute reserve product—Day-ahead Scheduling Reserve—is not actively maintained in real-time, “there is no guarantee the DASR will ensure that there are sufficient resources available in the operating day to recover the Synchronized and Primary Reserves.”⁸⁰

⁷⁹ Pilon Aff. ¶ 5.

⁸⁰ *Id.* ¶ 30.

3. *The lack of alignment between the day-ahead and real-time products is problematic as it causes commitment mismatches, price dislocation, and inefficient price arbitrage.*

The methodology used to schedule Day-ahead Scheduling Reserves day-ahead does not acknowledge the simultaneous need for 10-minute reserves. Rather, the current requirement for Day-ahead Scheduling Reserves is based on the average day-ahead load forecast error and average expectation of forced outages in real-time. If both of these averages occurred as the day-ahead model expects in real-time, then, when such real-time conditions deviate from the day-ahead's expectations, there could be no additional headroom for the additional 10-minute reserves that are needed in real-time.

The joint co-optimized method in which energy and reserves are procured simultaneously, and with regard to the cost of interchanging energy and reserves, means that the imposition of a requirement for 30-minute Day-ahead Scheduling Reserves will impact the commitment of resources in the day-ahead market and ultimately influence not only reserve and energy prices but also which resources are cleared to provide energy and which are cleared for reserves. This misalignment can also result in different transmission constraints between the day-ahead and real-time, leading to additional balancing congestion—a cost that is allocated to real-time load and exports.

In addition, under the current practice, there is no direct offset or guarantee that resources procured in the day-ahead market as Day-ahead Scheduling Reserve can provide 10-minute reserves in the real-time market. This is due to a number of factors. First, the performance requirements for the two products vary: one must be able to provide a specific amount of energy within 30 minutes, while the other must be able to provide energy within 10 minutes. A resource's physical characteristics (e.g., ramp rate) may preclude it from being capable of providing the same amount of reserves 10-minutes out, as it can 30-minutes out.

Second, given the differing time horizons, PJM's current 30-minute reserve requirement averages about 5,600 MW per hour, while the average 10-minute reserve requirement (Primary Reserve) in the real-time market is about 2,200 MW per hour. Thus, even if the current day-ahead procurement was associated with the current real-time obligations, there is no guarantee that at least 2,200 MW of the 5,600 MW scheduled in 30-minute reserves can be converted to energy in 10 minutes. For example, if 100 percent of the 30-minute reserves were offline resources that had times to start in excess of 10 minutes but less than 30 minutes, then none of the 30-minute reserves can provide 10-minute reserves. While this scenario is unlikely, it can occur and illustrates a deficiency not explicitly enforcing a 10-minute reserve requirement during the day-ahead scheduling process.

In addition, procuring a 30-minute reserve product in the day-ahead market when only 10-minute reserves are procured in real-time creates a modeling discrepancy between the day-ahead and real-time markets. Clearing the day-ahead market when modeling only a 30-minute reserve requirement, as opposed to modeling both a 30-minute reserve requirement and 10-minute reserve requirements, will likely produce the commitment of a different set of resources and different market clearing prices.⁸¹ Such disparate outcomes are the result of different reserve requirement constraints placed on the market clearing algorithm, to the extent such constraints bind. Accordingly, by not modeling 10-minute reserves in the day-ahead market, the market misses out on the most efficient set of resources or price outcomes based on the expected conditions in real-time. Further, PJM's current practice can result in higher costs to meet the 10-minute reserve requirements in real-time than would occur had those requirements been modeled in the day-ahead market.

⁸¹ The only time this will not produce a different commitment and dispatch solution is when meeting the 30 minute requirement simultaneously meets the 10 minute requirement. Without modeling a 10 minute requirement, explicitly, this would only occur by luck.

The energy price discrepancies between the day-ahead and real-time markets that result from modeling disparate reserve requirements in each market can provide opportunities for profitable Virtual Transactions⁸² that, while rational, do not benefit the market. Unlike with Virtual Transactions which can create market efficiencies due to the differences between supply and demand between day-ahead and real-time and the resulting price difference, the arbitrage opportunity that exists by having different reserve products in the day-ahead and real-time is not based on price differences, but rather exists through modeling differences due to the distinct products. While the arbitrage behavior may be rational and not against the market rules, in this circumstance such arbitrage will not lead to the market efficiencies that price convergence could engender for the simple reason that there are no prices to converge.

III. PJM PROPOSES JUST AND REASONABLE TARIFF CHANGES THAT DIRECTLY ADDRESS AND RESOLVE THE CURRENT, UNJUST AND UNREASONABLE, DESIGN FLAWS IN THE RESERVE MARKET RULES.

When the Commission finds that existing tariff terms are unjust, unreasonable, or unduly discriminatory under FPA section 206, it must establish the just and reasonable terms needed to replace the terms and conditions it found unlawful.⁸³ To ensure just and reasonable rates, PJM has developed, and hereby presents for Commission consideration, replacement terms and conditions to address and resolve the shortcomings, detailed above, that render the current reserve market rules unjust and unreasonable. To facilitate the Commission's determination of just and reasonable replacement terms, PJM has drafted, and includes with this filing, tariff revisions that would implement PJM's recommended approach to resolving the current flaws.⁸⁴

⁸² Tariff, section 1, Definitions T-U-V (defining Virtual Transaction as "a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction").

⁸³ See 16 U.S.C. § 824e.

⁸⁴ At the request of stakeholders, PJM posted its then-existing draft tariff revisions to its website on March 11, 2019. PJM reviewed its proposed revisions with stakeholders at a meeting held on March 14, 2019, and took comments on

A. *PJM Proposes to Consolidate the Tier 1 and Tier 2 Synchronized Reserve Products into One Synchronized Reserve Product to Ensure That Proper Incentives Are in Place for Consistent and Reliable Performance.*

PJM proposes to consolidate the Tier 1 and Tier 2 reserve products into one uniform Synchronized Reserve product, modeled closely after the Tier 2 product that exists today. To effectuate these reforms, PJM proposes to replace the terms “Tier 1” and “Tier 2” with the unified term “Synchronized Reserve” throughout the Tariff and Operating Agreement.⁸⁵ The consolidated reserve product will: (i) be assigned based on the market solution that maximizes social welfare (in part through minimizing production cost); (ii) be obligated to respond based on the assigned quantity; (iii) be compensated at the applicable clearing price for the assigned megawatt amount; and (iv) face a penalty if the resource does not respond during an event. The consolidated product will be treated comparably regardless of whether the reserves come from unloaded reserve capability or re-dispatched reserve capability. Revisions related to establishing the new crediting/offer structure for the unified Synchronized Reserve product are described in Section III.C, below.

As part of this consolidation, PJM also proposes to change the compensation structure for Synchronized Reserve. Under the current construct, the offer/compensation for Tier 1 Synchronized Reserve is the Synchronized Reserve Energy Premium Price, which is \$50/MWh, and which is intended to compensate generators for the added wear and tear and increased maintenance that result from a Synchronized Reserve event when generators must respond quickly over short periods of time. In addition to that, Tier 1 reserves are compensated the Tier 2 clearing price when the Non-Synchronized Reserve Clearing Price is greater than \$0.00/MWh.

whether the draft revisions appropriately implemented the reserve market changes PJM was directed to file by the PJM Board.

⁸⁵ See Operating Agreement, Schedule 1, sections 1.7.19A(a), 3.2.3A(b)(i), 3.2.3A(g), 3.2.3A(i), 3.2.3A(j); Proposed Operating Agreement, Schedule 1, sections 3.2.3A(b)(i), 3.2.3A(g), 3.2.3A(i), 3.2.3A(j).

Because PJM proposes to remove the Tier 1 product, both of the aforementioned methods of compensation to Tier 1 resources will be eliminated.⁸⁶ With respect to Tier 2, generators that provide Tier 2 Synchronized Reserve are currently compensated at the higher of (a) the clearing price or (b) the resource's cost to provide the service (including any applicable resource-specific condense start-up or energy consumption costs), the resource's offer to provide Synchronized Reserves, and unit-specific opportunity cost for supplying Synchronized Reserve. The Synchronized Reserve offer may not exceed the variable operations and maintenance ("VOM") cost plus a \$7.50/MWh adder. The clearing price is generally equal to the highest sum of a generator's Synchronized Reserve offer and the specific opportunity cost of the resource.

PJM proposes to change this offer structure for Synchronized Reserve in two primary ways. First, PJM will calculate a resource's availability and reserve capability MW using the availability and unit parameters offered in for energy, with some exceptions. For this provision, PJM will utilize the existing parameters that define a resource's flexibility that are submitted for use in the energy market such as Economic Minimum, Economic Maximum, and energy ramp rate. Additionally, participants will be provided with additional ability to update energy ramp rates intra-day and to update the Synchronized Reserve maximum MW intra-hour to enable more accurate representation of their reserve capability. Second, the VOM component will be removed from Synchronized Reserve offers (as this component is already included in energy offers) and the presently-effective \$7.50/MWh offer margin will be reduced to the expected value of the penalty.

A central goal of the market design for Synchronized Reserve offers is to ensure that resources on the margin are indifferent to providing reserves or energy. Allowing participants to

⁸⁶ See Operating Agreement, Schedule 1, sections 3.2.3A(b)(i), 3.2.3A(g), 3.2.3A(i), 3.2.3A(j).

express the risk they assume by accepting an obligation via the Synchronized Reserve offer is essential to ensuring that they are indifferent. In the context of PJM's proposed Tier 1/Tier 2 consolidation, the existing margin adder allows participants to express this risk. However, the existing \$7.50/MWh level of this adder is based on the implicit margins in actual offers made by participants for Tier 2 Synchronized Reserve prior to the implementation of the market in 2002.⁸⁷ These offers included market power, and were based on only two suppliers at the time.⁸⁸ As Mr. Keech explains,⁸⁹ the risk resources assume by accepting an obligation can be approximated by calculating the expected value of the Synchronized Reserve penalty, where:

$$\text{Expected Value of Synchronized Reserve Penalty} = \text{Average Penalty Rate} (\$/\text{MWh}) * \text{Probability of an Event} * \text{Probability of Underperformance}$$

The existing \$7.50/MWh margin is well in excess of the near \$0.00/MWh expected value of the Synchronized Reserve penalty resources may which takes into account the average penalty rate as well as the probabilities that a Synchronized Reserve Event will occur and that a resource will underperform in such event (expected value of penalty was \$0.01/MWh in 2017 and was \$0.02/MWh in 2018).⁹⁰ Accordingly, PJM proposes lowering the cap on the margin adder to the expected value of the penalty. Specifically, PJM proposes re-calculating this value on an annual basis. Rather than setting the cap to a static \$0.00/MWh based on current conditions, reassessing the cap on a periodic basis will allow the cap to change as clearing prices, and consequently the

⁸⁷ See PJM ER02-2519 Filing, *Report on Spinning Reserve Market By: Joseph E. Bowring – Manager PJM Market Monitoring Unit* ¶ 20 (“PJM’s MMU proposed a margin of \$7.50/MWh, which is incorporated in the Tier 2 Spinning Reserve market as part of the cost-based bid cap. The MMU calculated the margin based on an analysis of the margins implicit in the historic actual offers made by participants for Tier 2 Spinning Reserve. In its calculation, the MMU used the revenues received at the accepted level of offers and netted out energy costs and O&M costs to arrive at the margin. Thus, the proposed margin is based on the historic actual margins offered and received by market participants for Spinning Reserve.”).

⁸⁸ *Id.* ¶ 13 (“The concentration in the Spinning Reserve market was extremely high, equivalent to less than two suppliers of equal size, on average, providing Spinning Reserve.”).

⁸⁹ Keech Aff. ¶ 57.

⁹⁰ Mr. Keech explains how PJM calculated the expected penalty value. See Keech Aff. ¶¶ 55-58.

expected value of the penalty, are ultimately impacted by the proposed reserve market enhancements.

The consolidation of the Tier 1 and Tier 2 reserve products into a single, unified product (inclusive of the reforms to the associated offer structure described above) is just and reasonable, for the following reasons. First, the Commission has approved a single, consolidated product for synchronized (or spinning) reserve in every other jurisdictional RTO/ISO in the United States, and there is no compelling reason why PJM, in isolation, should continue to deviate from this standardized concept that has worked well in other markets. Second, consolidation will provide more accurate reserve calculations that require less operator intervention. As Mr. Pilonig explains, the structural deficiencies inherent in the Tier 1 product prevent PJM operators from developing accurate estimates of the amount of Tier 1 reserves that will reliably respond at any given time, and force PJM operators to compensate through biasing and out-of-market actions.⁹¹ Third, by attaching a penalty to all Synchronized Reserve products, consolidation will improve Synchronized Reserve performance by holding all applicable resources accountable for actually providing their assigned reserves. Fourth, consolidation will provide consistent compensation for all resources providing the same service. As currently structured, PJM has two distinct products that provide the exact same service, and clear the exact same auction, yet are paid two different prices. Finally, consolidation will provide more accurate energy and reserve pricing due to improved Synchronized Reserve measurement. Given this, PJM asks the Commission to accept as just and reasonable PJM's proposal to consolidate the Tier 1 and Tier 2 products into one Synchronized Reserve product.

⁹¹ See Pilonig Aff. ¶¶ 15-20.

B. PJM's Proposed Method for Determining the Operating Reserve Demand Curves Is Just and Reasonable.

1. *The proposed \$2,000/MWh Reserve Penalty Factor properly reflects the cost of obtaining reserves when PJM is entering a reserve shortage.*

Given the particular circumstances of PJM's market, the Reserve Penalty Factor should be increased to \$2,000/MWh so that market prices will reflect the cost of reserves PJM needs to satisfy NERC standards.

The Reserve Penalty Factor is intended to represent the maximum production cost the market is willing to pay to maintain the MRR and avoid a reserve shortage.⁹² Because the Reserve Penalty Factor acts as a cap on the cost the market is deemed willing to incur to satisfy the MRR, the market will not commit a resource for reserves if the resource's cost to provide reserves exceeds the Reserve Penalty Factor. However, *the market's* refusal to recognize that resource, does not prevent *PJM* from relying on that resource. Indeed, to maintain the minimum reserves required in accordance with NERC standards, PJM dispatchers *will* commit all generation, even generation costing above the existing \$850/MWh Reserve Penalty Factor, and will deploy pre-emergency and emergency load management reductions, also costing well above \$1,000/MWh. The market price of reserves simply will not reflect the cost of such resources if the penalty factor is not set at a level at least as high as the cost of these actions, notwithstanding that they are needed to maintain the reserve requirement.

Specifically, under PJM's particular market rules, PJM system operators can commit resources, or buy energy, at costs in excess of the existing \$850/MWh penalty factor in the following circumstances when needed to maintain reserves:

- Generation resources can submit verified cost-based incremental energy offers of up to \$2,000/MWh;

⁹² See, e.g., *Keech Aff.* ¶ 16.

- Emergency and pre-emergency demand response resources can submit offers up to \$1,849/ MWh to reduce demand with 30-minutes lead time;
- Emergency and pre-emergency demand response resources can submit offers up to \$1,425/ MWh to reduce demand with one-hour lead time;
- Emergency and pre-emergency demand response resources can submit offers up to \$1,100/ MWh to reduce demand with two hours lead time;
- In the case of Synchronized Reserves, initiating a voltage reduction; and
- Emergency energy may be purchased from neighboring regions at offers levels that are uncapped. These transactions are presently capped at \$2,700/MWh for price-setting purposes and PJM proposes to further modify that cap to \$2,000/MWh as part of this filing.

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.

If such resources nonetheless *are* committed as reserves, the reserve clearing market price will not reflect such resources' offers and lost opportunity costs, even if such a resource's offer plus lost opportunity cost would have been the marginal offer needed by PJM to meet its MRR. Instead, that seller will be paid its cost to provide the service—both its offer and lost opportunity cost—as out-of-market uplift. The seller's cost, in other words, will be treated on a 'pay-as-bid' basis, rather than as the marginal price-setting offer. This current practice unreasonably undervalues reserves and sends a weak, muted, signal of the value of flexibility on the PJM system.

That treatment is contrary to a long line of Commission precedents approving single clearing price markets, which "create[] incentives for sellers to minimize their costs, because

cost reductions increase a seller's profits."⁹³ As the Commission has explained, "when many sellers work to minimize their costs, competition keeps prices as low as possible [which] benefits customers, because over time it results in an industry with more efficient sellers and lower prices."⁹⁴ By contrast, "a pay-as-bid auction would likely result in higher, not lower, [wholesale] prices because parties would be far less likely to bid their marginal costs if they are only paid at their offer price."⁹⁵ In the pay-as-bid model, suppliers are incentivized to bid as high as possible while still receiving a commitment. The single-clearing-price model (including PJM's long-standing energy market rules) creates the opposite incentive—a seller is paid nothing unless it offers at or below the last offer needed to clear the market, and profits to the extent it can offer below that level.

Reflecting this deeply rooted, longstanding Commission policy, multiple PJM markets are single-clearing price markets. Indeed, PJM's real-time energy market has relied on a single clearing price approach to set locational, marginal cost-based prices for over twenty years.⁹⁶ Evolving market rules in PJM, including the 2017 rule change allowing cost-based energy offers of up to \$2,000/MWh, make clear that in order to retain the benefits of a uniform clearing price market for reserves, it is reasonable as part of a remedy of the issues detailed above with PJM's present reserve pricing paradigm for the penalty factor to be increased to \$2,000/MWh, and allow reserve resources with costs of up to \$2,000/MWh to set prices when they are needed at the margin to meet PJM's MRR.

⁹³ RPM Settlement Order at P 141 (2006); *see also* *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318 at P 195 (2007); *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); *Cal. Indep. Sys. Operator Corp.*, 112 FERC ¶ 61,013, at PP 34, 36 (2005); *New England 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).

⁹⁴ *Id.*

⁹⁵ *Midwest Indep. Transmission Sys. Operator, Inc.*, 125 FERC ¶ 61,060, at P 41 (2008).

⁹⁶ *See* Hogan & Pope PJM ORDC Report at 7.

As Mr. Keech explains, “PJM’s primary focus,” as it developed a replacement for the currently understated penalty factor, was to set it “at 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. This price is \$2,000/MWh.”⁹⁷ The Reserve Penalty Factor therefore will reliably signal a shortage caused by running out of reserves, rather than simply an economic choice to go short on reserves.

As Mr. Keech explains, the proposed Reserve Penalty Factor is not based on an estimated value of lost load (“VOLL”).⁹⁸ While VOLL estimates have often been considered, and sometimes adopted, in shortage pricing programs, that option is not a compelling choice for the PJM Region, which has developed and relied upon a capacity market for over 10 years. Mr. Keech differentiates between the Hogan & Pope model and PJM’s proposed implementation which, while both center on ensuring the MRR (or security minimum in the Hogan & Pope model) are maintained, he explains, in PJM’s implementation the MRR:

[I]s not the point at which PJM will begin shedding load; rather it is the point at which PJM will no longer be able to meet its minimum requirement of a specific reserve type. Because PJM is not shedding load at this point, the price on the ORDC for violating the MRR is not the VOLL, it is the maximum willingness to pay to maintain that reserve product.⁹⁹

Dr. Hogan and Dr. Pope recognize “there are logical variations and enhancements corresponding to differences in how ISOs define the points at which they will curtail load or take emergency actions,”¹⁰⁰ which impacts formulation of an ORDC. Consistent with Mr. Keech’s explanation, they continue, “PJM is proposing a Penalty Factor based on the maximum cost at which

⁹⁷ Keech Aff. ¶ 9.

⁹⁸ Keech Aff. ¶ 7.

⁹⁹ Keech Aff. ¶ 15.

¹⁰⁰ Hogan & Pope PJM ORDC Report at 16.

resources could be procured based on market offers, rather than on the VOLL, as the anchor for its ORDCs.”¹⁰¹ Ultimately, Dr. Hogan and Dr. Pope conclude that:

PJM’s formulation of its ORDCs is consistent with the theory presented here about how the value of incremental reserves will vary with the probability of loss of load during actual operation, but is anchored around PJM-specific assumptions about the actions that will be taken as the level of reserves declines below the MRR.¹⁰²

As is the case today, the Reserve Penalty Factor sets a horizontal segment of the ORDC at all reserve levels from zero to the MRR, and defines the start of a vertical segment at the MRR. The vertical segment of the curve reflects that PJM operators will always endeavor to assign reserves up to the MRR (in furtherance of NERC standards). Under the existing approved energy market rules, as shown above, the cost of taking those actions can, under multiple circumstances, exceed \$850/MWh, and range as high as \$2,000/MWh under non-emergency conditions and exceed \$2,000/MWh in emergency conditions. As Mr. Keech explains, PJM proposes establishing the same penalty factor for all reserve requirements, including Synchronized Reserve, Primary Reserve, and 30-minute Reserve.¹⁰³ Although some may argue the lower quality product (30-minute Reserve) should have a lower penalty factor, Mr. Keech points out the issues disparate penalty factors would have, noting that extreme system conditions result in PJM potentially not deploying all of the economic resources (possibly capacity resources) it has available to maintain 30-minute Reserves. This is not only inconsistent with how PJM operates its system, it would also require an arbitrary determination of a lower penalty

¹⁰¹ *Id.*

¹⁰² *Id.* at 17.

¹⁰³ Keech Aff. ¶ 13.

factor for this product that cannot be justified. For these reasons, PJM is also proposing to implement a \$2,000/MWh Reserve Penalty Factor for 30-minute Reserves.¹⁰⁴

Unlike the current ORDC, as discussed in the following section, the segment begins as a vertical line, but then slopes down and to the right, assigning a positive but diminishing value to reserves procured in excess of the MRR. As also discussed below, that sloped portion of the ORDC captures the probabilities of forecast error and generator non-performance in real time.

2. *The proposed downward-sloping ORDC is reasonably defined by the uncertainty of meeting the MRR.*

As shown above, PJM's current-approved ORDC values reserves above the minimum reserve requirement with a step extending 190 MWh beyond the MRR, at a price of \$300/MWh.¹⁰⁵ While this step is helpful, and embodies the Commission's prior acceptance that such reserves have value, PJM's current added step is not based on a systematic assessment of the value of reserves beyond the MRR.

In simplest terms, the value of any given quantity of reserves above the MRR depends on the likelihood that real-time conditions could negate or exhaust reserves of that quantity, resulting in a shortage below the MRR. That is the same type of concern PJM dispatchers attempt to address as they take actions "to ensure that system balance and reserve requirements are maintained as we progress through the Operating Day."¹⁰⁶ PJM's "forward-looking energy and reserve co-optimization engine . . . uses [various demand and supply] forecasts to project the total change in system demand and how to meet that demand change."¹⁰⁷ But "the flaw" in

¹⁰⁴ See proposed Operating Agreement, Schedule 1, section 3.2.3.01(d)(iii).

¹⁰⁵ See *supra* note 58, regarding the conditional step extension.

¹⁰⁶ Piloni Aff. ¶ 5.

¹⁰⁷ *Id.* ¶ 8.

that approach is that the optimization assumes “the forecasts are perfect.”¹⁰⁸ Because PJM dispatchers know that is not the case, they “bias” the dispatch schedules to account for the “error in forecasts and generator response that they observe on a daily basis during real-time operations.”¹⁰⁹ As Mr. Pilon explains, “[t]he components of the forecasts that are most critical to maintaining real-time power balance are load forecasting, interchange forecasting, and generation performance/availability forecasting.”¹¹⁰ Mr. Pilon emphasizes that, “in the current market construct, the bias is an absolute necessity to ensure reliability given the uncertainty in the forecasts used in the commitment process.”¹¹¹ To this point, Mr. Pilon provides an analysis of 2018 data demonstrating the critical role biasing plays in preventing PJM from entering into a reserve shortage. Specifically, the possibility analysis finds that in 29.1 percent of all five-minute intervals in 2018, PJM system operators would have been short reserves absent the positive bias applied in the scheduling engines for that interval.¹¹² The average amount of positive bias applied in such cases (i.e., the amount of increased demand) was 1,471 MWs.¹¹³ He notes that “[i]f the recommended ORDC curves were incorporated, the need for operators to manually intervene in SCED cases would decrease, the reserve requirements would be more reflective of actual operator needs, and prices would be more reflective of operator actions.”¹¹⁴

¹⁰⁸ *Id.* ¶ 8.

¹⁰⁹ Pilon Aff. ¶ 8.

¹¹⁰ *Id.* ¶ 6.

¹¹¹ *Id.* ¶ 9.

¹¹² Pilon Aff. ¶ 12-16.

¹¹³ *Id.* As Mr. Pilon notes, 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. *Id.* ¶ 16.

¹¹⁴ Pilon Aff. ¶ 17.

However, as currently employed in PJM operations, “this bias is not developed formulaically or in a manner that is 100 percent consistent from dispatcher to dispatcher.”¹¹⁵

PJM therefore proposes to shift the burden of addressing these system balance and reserve requirement uncertainties from the dispatchers (as much as practicable and prudent) to the market, and to describe those uncertainties systematically and formulaically. To accomplish this, PJM proposes a curve that is directly based on and determined by the uncertainty that forecast errors and similar uncertainties will cause the system to fall short of the MRR. Because the risk of falling below the MRR diminishes to the extent reserve levels exceed the MRR, this approach of basing the ORDC on quantification of uncertainty also results in a curve that gradually slopes down and to the right. This change to the ORDCs will reasonably resolve the price suppression and uplift concerns, described above, that make the current ORDCs unjust and unreasonable. The proposed ORDCs, by capturing real-time market uncertainties, also would go a long way toward systematically reducing the need for PJM operators to take actions based on their notions of real-time market uncertainties.

For comparison back to the model discussed by Dr. Hogan and Dr. Pope,¹¹⁶ their proposed loss of load is translated into an event in which the amount of reserves is less than a minimum reserve requirement. If reserves are anticipated to fall below this MRR, emergency actions are triggered, which may be a precursor to load curtailment. The relevant metric is, therefore, the loss of load probability, or, in PJM parlance, the probability of reserves falling below the minimum reserve requirement (“PBMRR”). For example, if the MRR is 1,400 MW and PJM is currently carrying 1,700 MW of reserves, then PJM would have 300 MW of reserves in excess of the MRR. However, based on forecast uncertainty, there is a non-zero probability

¹¹⁵ *Id.* ¶ 9.

¹¹⁶ See Hogan & Pope PJM ORDC Report at 4.

that the net forecast error exceeds 300 MW between when PJM commits the 1,700 MW of reserves and 30 minutes from that time (the time for which those reserves were procured). This probability, multiplied by the \$2,000/MWh penalty factor, determines the maximum incremental cost that the system is willing to incur to maintain that level of reserves and is also used in the determination of the clearing price for that product.

Dr. Rocha Garrido describes PJM's systematic, formulaic, probabilistic quantification of these uncertainties in detail in his affidavit. Here, the relevant quantification is the probability that the total error in real-time forecasts (adjusted for any factors that mitigate that uncertainty) is greater than any given reserve level in excess of the MRR. If total error at a given reserve quantity above MRR *does* exceed that reserve quantity, then the MRR cannot be met and the reserve price on the ORDC associated with that reserve quantity is appropriately triggered to determine LMPs and reserve market clearing prices.

Quantifying these uncertainties systematically presents several questions:

- What are the main sources of the relevant uncertainty;
- What factors, if any, are known to the operator at the time of the forecast that reliably and predictably reduce those uncertainties;
- What is the appropriate “look-ahead” period, i.e., the time between the forecast and the actual occurrence of the conditions addressed by the forecast;
- What span of historic data should be considered to measure the observed error rate in the relevant forecasts;
- What periods within the year should be assessed to recognize patterns of variation in forecast error during the year; and
- How should the uncertainty reflected in the overall net error be incorporated into the ORDC?

Dr. Rocha Garrido addresses each of these questions, taking into consideration use of the relevant information by system operators as supported by Mr. Pilog, and demonstrates PJM's

rigorous approach to embodying in the ORDC these probabilities that the system could fall short of the MRR in real-time.

- a. Probabilities of falling short of MRR are reasonably estimated from uncertainties concerning demand (load forecast error) and supply (intermittent generation forecast error and thermal plant forced outage risk).

The relevant sources of uncertainty are the same as those confronted by PJM system operators throughout the day. As Mr. Pilonig explains, “[t]he components of the forecasts that are most critical to maintaining real-time power balance are load forecasting, interchange forecasting, and generation performance/availability forecasting.”¹¹⁷ As he notes, PJM “has automated tools that develop these forecasts, as well as PJM staff members that maintain and calibrate these automated tools to ensure that they are as accurate as possible.”¹¹⁸ Nonetheless, “some level of error will always be present in forecasts.”¹¹⁹ Dr. Rocha Garrido adds to this list another factor that, while not a forecast, per se, is a key uncertainty confronted by system operators (i.e., the ever-present risk of unscheduled thermal plant outages).¹²⁰ As it happens, PJM has ample data from the historic operation of its system to quantify these uncertainties, i.e., the difference between the forecast or a value (made at the start of a specified look-ahead period) and the actual value observed at the end of that time period.¹²¹

Observed forecast errors, unsurprisingly, are essentially random. Indeed, if there were a pattern to a particular error, it would indicate a flaw in the forecast method, which—once corrected—would leave only random errors once again. Thus, to quantify the uncertainties

¹¹⁷ Pilonig Aff. ¶ 6.

¹¹⁸ *Id.*

¹¹⁹ *Id.*

¹²⁰ Rocha Garrido Aff. ¶ 11.

¹²¹ As discussed in section III.B.2.(c) below, PJM proposes a 30-minute uncertainty measurement period for Synchronized and Primary Reserves, and a 60-minute uncertainty measurement period for 30-Minute Reserves.

associated with these errors, PJM proposes to use historical data to derive probabilistic distributions of the errors. Such probabilistic distributions can then be used to estimate the probability that, for example, the load forecast error is greater than a given value of reserves above the MRR. In his affidavit, Dr. Rocha Garrido lists and describes the data sources for each of these sources of forecast error and uncertainty.¹²² As he notes, interchange error is a consideration for the 30-minute reserve product, but not for either of the 10-minute reserve products.¹²³

b. The regulation requirement reduces the probability that the system will fall short of the MRR in real-time.

While the factors noted above increase uncertainty, another factor—PJM’s regulation requirement—directly reduces that uncertainty. PJM has a stated regulation requirement, prescribing a minimum MW level of regulation service PJM must obtain during defined ramp or non-ramp time periods. Operators can reasonably assume, at the beginning of the look-ahead period, that regulation service will be procured in the prescribed quantity, and will directly reduce the likelihood of falling short of the MRR at the end of the look-ahead period. PJM reasonably includes that same factor to mitigate uncertainty in PJM’s probabilistic quantification for purposes of the ORDC.¹²⁴

Specifically, the regulation requirement is 800 MW during “ramp hours,” i.e., the 8 to 13 (varying by season) typically higher load hours each day, and 525 MW during the “non-ramp hours,” i.e., the 9 to 12 (varying by season) typically lower load hours each day.¹²⁵

¹²² Rocha Garrido Aff. ¶ 11.

¹²³ *Id.* ¶ 15. As he explains, the 30-min net interchange schedule forecast error is zero. Therefore, net-interchange schedule uncertainty does not apply to the calculation of the SR and PR ORDCs. *Id.* ¶ 15.

¹²⁴ *Id.* ¶ 5.

¹²⁵ PJM, *Manual 12: Balancing Operations*, § 4.4.3 (rev. 39, Feb. 21, 2019), <https://www.pjm.com/~media/documents/manuals/m12.ashx>.

- c. Thirty minutes is a reasonable look-ahead period for the 10-minute reserve requirements; and 60 minutes is a reasonable look-ahead period for the 30-minute reserve requirements.

The look-ahead time period defines how PJM measures forecast error for purposes of the ORDC: the forecast at the start of the defined look-ahead period is compared against the actual observed condition at the end of the look-ahead period. The look-ahead period appropriately differs between the two 10-minute reserve requirements and the 30-minute Reserve Requirement.

Specifically, Synchronized Reserve and Primary Reserve are met with resources expected to respond within the next 10 minutes from the target time. Given that procurement lead time, PJM reasonably proposes a 30-minute look-ahead uncertainty interval for Synchronized Reserve and Primary Reserve, to account for the total time elapsed between the reserve assignment and the reserves' response time. For the 30-minute Reserve Requirement, PJM reasonably proposes a 60-minute interval for measuring uncertainty, also to account for the total time elapsed between the reserve assignment and the reserves' response time. As Dr. Hogan and Dr. Pope find, "[t]his approach is a reasonable way to account for the uncertainty in estimating the value of operating reserves because it appropriately accounts for the multi-period nature of forecast uncertainties."¹²⁶

Elaborating on these look-ahead periods, Dr. Rocha Garrido explains that, for Synchronized Reserve and Primary Reserve, 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.¹²⁷ Similarly, as he explains, for

¹²⁶ Hogan & Pope PJM ORDC Report at 18.

¹²⁷ Rocha Garrido Aff. ¶ 13.

30-minute Reserves, the length of the look-ahead interval is at least 40 minutes.¹²⁸ PJM is proposing to use 30 minutes and 60 minutes, respectively, as the corresponding look-ahead periods for estimation of the uncertainties. The additional duration of time in the look-ahead period in each case (10 added minutes for the Synchronized and Primary Reserve Requirement and 20 added minutes for 30-minute Reserve Requirement) is intended to capture deviations from when the RT SCED case is run, and also to capture the value of reserves in subsequent intervals, which is not captured when solving the RT SCED case for a single interval.¹²⁹

As Dr. Rocha Garrido explains, these look-ahead timeframes also align with the operator actions available to address uncertainty within the prescribed timeframe.¹³⁰ For system uncertainty arising in the 0-30 minute timeframe, for example, the relevant actions are: (i) deploying regulation; (ii) attempting to run the RT SCED to adjust the system based on errors in the forecast; and/or (iii) initiating a Synchronized Reserve event.¹³¹ As Dr. Rocha Garrido points out, “[a]ll of the actions available within the 0-30 minute timeframe include the use of 10 minute reserves, illustrating it as a reasonable time proxy over which to measure their value.”¹³²

- d. PJM reasonably proposes to use three calendar years of data to estimate these uncertainties, and to measure the net error separately for each of 24 time blocks within the year.

To estimate these uncertainties, PJM proposes to use historical data from the most recent three full calendar years. Once implemented, the historic data period would, each year, roll forward one year. As Dr. Rocha Garrido explains, the choice of three years strikes a balance

¹²⁸ *Id.*

¹²⁹ *Id.*

¹³⁰ *Id.* ¶ 14.

¹³¹ Rocha Garrido Aff. ¶ 14.

¹³² Rocha Garrido Aff. ¶ 14.

between reducing the impact that a single year may have on the probabilistic distribution, versus removing old error data that may not reflect the most up-to-date status of PJM forecasting models.¹³³

Because uncertainties and forecast errors could vary meaningfully by season and time of day, PJM proposes to measure uncertainty in each of twenty-four combinations of time-of-day blocks and season. The choice of twenty-four probabilistic distributions strikes a balance between (i) quantifying the uncertainty during specific periods that are expected to have larger uncertainties (such as the morning period in winter) relative to periods that are expected to have smaller uncertainties (such as the night-time period in the fall) and (ii) avoiding a large number of ORDCs which may result in market outcomes that change too frequently. Since the probabilistic distributions are the basis for estimating the value of reserves, i.e., the prices in the ORDCs, the choice of twenty-four probabilistic distributions results in twenty-four ORDCs. Specifically, as shown by Dr. Rocha Garrido, PJM proposes to use combinations of the following seasons and time of day blocks:

Season	Time-of-Day Block (in Hour Beginning)
Summer (June – August)	1 (2300 – 0200)
Fall (September – November)	2 (0300 – 0600)
Winter (December – February)	3 (0700 – 1000)
Spring (March – May)	4 (1100 – 1400)
	5 (1500 – 1800)
	6 (1900 – 2200)

Combining these parameters for the historic data used to assess uncertainty, PJM proposes:

- For load, wind, solar and net-interchange schedule forecasts, assessing the 30-minute and 60-minute errors (i.e., actual value minus the x-minute ahead forecast value where x is either 30 or 60) for each of six four-hour daily time blocks in each of four three-month seasons.

¹³³ *Id.* ¶ 15.

- For the 30-minute and 60-minute Forced Outages uncertainty, calculating the amount of megawatts that have experienced partial or full forced outages in 30-minute and 60-minute intervals, respectively, using data from the PJM Generator Availability Data System (“eGADS”) system¹³⁴ for each of six four-hour daily time blocks in each of four three-month seasons.
- e. Aggregating these uncertainties yields a probability distribution that defines the shape and slope of the demand curve.

As Dr. Rocha Garrido explains, PJM proposes to use the concept of expected value to calculate the incremental value of reserves in excess of the MRR.¹³⁵ As used here, expected value refers to the weighted average outcome of a given decision when all possible outcomes are considered, weighted by the probability of each outcome. In the context of the ORDC, the decision is procuring reserves in excess of the MRR, where the binary outcomes are: (1) meeting the MRR; or (2) failing to meet the MRR. Meeting the MRR entails no penalty whereas failing to meet the MRR triggers the penalty factor.¹³⁶

As explained above, establishing the value of reserves in excess of the MRR depends on calculating the probability of not meeting the MRR when the given reserve levels in excess of the MRR are available, taking account of the relevant uncertainties and uncertainty-mitigating factors. The prior section explained the relevant uncertainties, and how each is measured. This section explains how the uncertainties are then aggregated, and how they are used to form a probabilistic distribution, which in turn dictates the shape of the downward sloping part of the ORDC.

Specifically, for each time-of-day block in the three full calendar years, the forecast error data from the individual demand and supply uncertainties described above, is combined with the regulation requirement data to calculate each time-of-day block’s net load forecast error. Dr.

¹³⁴ All generating facilities in the PJM footprint are required to report outages using the PJM eGADS system.

¹³⁵ Rocha Garrido Aff. ¶ 17.

¹³⁶ Rocha Garrido Aff. ¶ 17.

Rocha Garrido presents the relevant formula, but in simple terms, the actual values for load, interchange (for 30-minute Reserve), solar output, and wind output are netted against the forecast values.¹³⁷ Then thermal unit forced outages increase the net load error, while the regulation requirement reduces the net load error.¹³⁸

This net load error is then used to calculate the probability of falling below the MRR, or PBMRR. For example, assume PBMRR is the probability of failing to meet the MRR when X reserves in excess of the MRR are available given all the uncertainties and uncertainty-mitigating factors. As shown by Dr. Rocha Garrido, the expected value of X reserves in excess of the MRR under these circumstances is appropriately expressed as PBMRR (X) x Reserve Penalty Factor.¹³⁹ Thus, for reserve quantities *between zero and the MRR*, where the PBMRR is 100 percent, the incremental value of additional reserves is the Reserve Penalty Factor. For reserve quantities *in excess of the MRR*, the incremental value of additional reserves is PBMRR (X) x Reserve Penalty Factor.¹⁴⁰

Because PJM uses empirical data (i.e., three years of historic data) to calculate uncertainty, PJM uses the actual distribution of that net load error data to construct the curves. Each of the twenty-four sets of net load error values from the most recent three full calendar years is used as the net load error empirical probabilistic distribution. Given these empirical distributions, there is no need to rely on a simplifying assumption of a “normal” distribution.¹⁴¹

¹³⁷ *Id.* ¶ 15.

¹³⁸ *Id.*

¹³⁹ Rocha Garrido Aff. ¶ 17.

¹⁴⁰ *Id.*

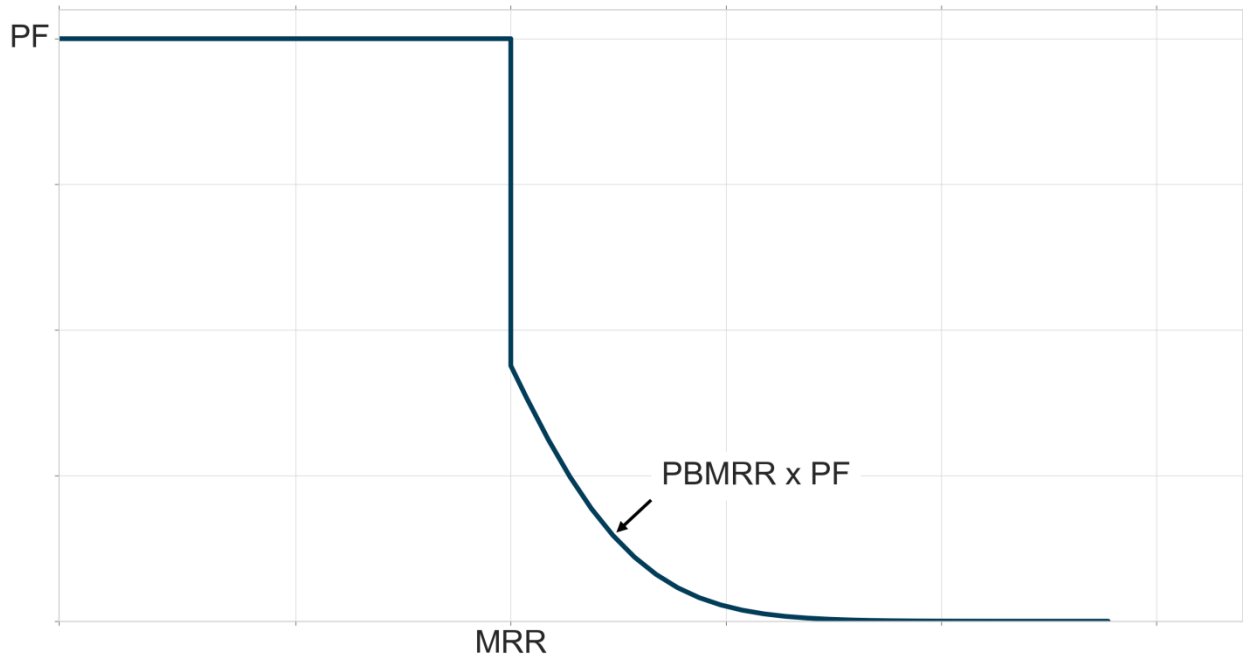
¹⁴¹ A normal distribution assumes a symmetric bell-curve distribution, centered on the mean value of the data, and with the span of the bell curve based on the standard deviation of the data.

The calculation of the PBMRR associated with X megawatts of reserves in excess of the MRR using the empirical net load error distributions is performed by counting the number of observations in the empirical distribution that are greater than X, divided by the total number of observations in the empirical distribution. The multiplication of this PBMRR times the applicable Reserve Penalty Factor provides the price associated with X megawatts of reserves in excess of the MRR in the applicable ORDC.

Repeating this calculation for multiple levels of reserves in excess of the MRR results in the downward-sloping segment of the proposed ORDCs. That slope does not begin, however, at the level of the Reserve Penalty Factor. Rather, as seen in Figure 8 below, there is an initial vertical line that drops down from the intersection of the MRR and the Reserve Penalty Factor. The curve sloping down and to the right begins at a point well down that vertical segment. This reflects two factors: (i) the formula of PBMRR (X) x Reserve Penalty Factor would produce outputs below the Reserve Penalty Factor at points before the MRR is met; but (ii) all reserve shortages (i.e., all reserve levels below the MRR) need to be priced at the Reserve Penalty Factor to reflect the critical importance of curing reserve shortages.¹⁴² Consequently, the first MW of added reserves above the MRR will be priced well below the Reserve Penalty Factor. From that point, as reserve quantities increase beyond the MRR, the price gradually decreases, signaling that the system has better capability to deal with the real-time uncertainties that may trigger an MRR shortage. Eventually, the prices in the ORDC drop to zero, signaling that procuring additional reserves provides no incremental value, because the probability of experiencing real-time uncertainties of the same magnitude as the amount of additional reserves is zero.

¹⁴² Rocha Garrido Aff. ¶ 19.

Figure 8. Proposed ORDC Shape



With respect to the width of the curve, PJM's proposed ORDC is data-driven with the downward-sloping segment based on observed recent historical uncertainty. As such, the resulting width of the ORDC is a reflection of several PJM-specific observations. First, PJM is a large system. By extension, even a small load forecast percent error (e.g., one percent) is a sizable amount relative to the MRR associated with each reserve requirement. The same observation can be made regarding forced outages of thermal units. Second, renewable (wind and solar) penetration is low relative to the total generation in the PJM system, but impactful for reserve procurement. Wind and solar resources still represent a small share of the PJM resource fleet. However, the magnitude of the uncertainty associated with forecasting the current absolute penetration levels of wind and solar resources is large relative to the MRR associated with each reserve requirement. Expected increased penetration levels are likely to increase the magnitude of the forecasting uncertainties. However, as Dr. Rocha Garrido notes, if PJM forecasting

models were to become more accurate in the future, such accuracy improvements would be reflected in the ORDCs by reducing the width of the downward-sloping segment.¹⁴³

3. *Each of the three reserve requirements, i.e., Synchronized Reserve, Primary Reserve, and 30-minute Reserve reasonably has its own demand curve.*

PJM proposes separate ORDCs for each of the three reserve requirements, i.e., Synchronized Reserves, Primary Reserves, and 30-minute Reserves. The system needs all three requirements, each contributes to PJM satisfying a distinct minimum reserve requirement, each warrants its own Reserve Penalty Factor, and each has value at levels beyond the applicable MRR. Therefore, each is reasonably procured through an ORDC that relates a Reserve Penalty Factor to an MRR, and that slopes down and to the right for reserves beyond the MRR, to help PJM manage the uncertainty of satisfying the MRR in real-time.

4. *Zonal demand curves properly reveal the cost of locational reserve shortages.*

The PJM Region, as a whole, has minimum reserve requirements, as dictated by NERC standards. But subsets of the PJM Region also can have reserve requirements, if there are limits on the sub-region's ability to import reserves from the rest of the PJM Region. Therefore, in addition to calculating and using PJM Region ORDCs, PJM also will calculate and use zonal ORDCs.

Notably, zonal ORDCs are not new with this filing. PJM determines and uses zonal ORDCs today. Because zonal ORDCs are developed in essentially the same way as PJM Region ORDCs, except with zonal (rather than PJM Region) data, the current Tariff describes no separate process or rules for these zonal ORDCs. PJM proposes no change to that existing Tariff

¹⁴³ Rocha Garrido Aff. ¶ 20. Note that Dr. Rocha Garrido sponsors two tables in his Affidavit that show the 30-minute and 60-minute mean and standard deviation of the observed forecasts' errors and forced outages of thermal units for the summer peak period (summer afternoon) and a winter peak period (winter morning) in 2015-2017.

convention. However, for completeness and transparency, Dr. Rocha Garrido describes PJM's zonal ORDC calculation process in his affidavit at paragraph 25.

5. *PJM proposes Tariff revisions to codify the proposed ORDCs.*

Modeled on the Tariff description of the Variable Resource Requirement curve used to clear Base Residual Auctions in PJM's capacity market, proposed Operating Agreement, Schedule 1, section 3.2.3A.02 codifies the ORDCs described above. Subsection (a) provides that PJM shall "shall establish Operating Reserve Demand Curves for clearing 30-minute Reserve, Primary Reserve, and Synchronized Reserve" for clearing the reserve markets.¹⁴⁴ Subsection (b) describes the ORDCs themselves, with the curve plotted such that the y-axis represents price and the x-axis represents megawatts.¹⁴⁵ Each curve: (1) starts at the intersection with the y-axis at \$2,000/MWh;¹⁴⁶ (2) moves in a straight line right until it hits the applicable minimum reserve requirement;¹⁴⁷ (3) then drops in a straight down along the minimum reserve requirement until the price (y-axis) equals "the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring an infinitesimal amount of additional MW of reserves beyond the minimum reserve requirement;"¹⁴⁸ and (4) from this point until the x-axis the curve is a function of the Reserve Penalty factor times the "probability of falling below the applicable minimum reserve requirement when procuring each additional MW of reserves beyond the minimum reserve

¹⁴⁴ Proposed Operating Agreement, Schedule 1, section 3.2.3A.02(a).

¹⁴⁵ Proposed Operating Agreement, Schedule 1, section 3.2.3A.02(b)(i).

¹⁴⁶ Proposed Operating Agreement, Schedule 1, section 3.2.3A.02(b)(ii)(A).

¹⁴⁷ Proposed Operating Agreement, Schedule 1, section 3.2.3A.02(b)(ii)(B).

¹⁴⁸ Proposed Operating Agreement, Schedule 1, section 3.2.3A.02(b)(ii)(C).

requirement until the resulting product falls below \$0.01/MWh at which point the curve will intersect with the x-axis.”¹⁴⁹ PJM also proposes to post each ORDC.¹⁵⁰

6. *PJM proposes to regularly develop multiple operating reserve demand curves, reflecting that the value of reserves can vary by product, time block, and location.*

As explained above, the uncertainties defining the ORDC are quantified from three full calendar years of data. Upon implementation of this proposal, PJM will annually update the determination of these quantifications to account for the most recent calendar year’s data. PJM will post the revised ORDCs each year by April 1, which allows time for reporting and collection of the data (such as forced outage history) that enters into these calculations.¹⁵¹

7. *By design, changes in reserve and energy revenues resulting from this proposal will impact future capacity market prices via the energy and ancillary services revenue offset.*

The PJM markets are designed to work in tandem to ensure that competitive resources have the opportunity to earn revenues sufficient to cover at least their total costs through the combination of revenue streams available given the various products.¹⁵² Competitive resources, the most economical set to provide each product, can earn revenues through the energy and ancillary service markets in day-ahead and real-time, and also through the Reliability Pricing Model capacity market on a forward basis. The interaction between these markets is accomplished through the existing Tariff provisions that provide for an offset to potential capacity revenues given anticipated, potential revenues in the energy and ancillary service (“EAS”) markets called the “EAS revenue offset.” Under the existing Tariff, PJM estimates the revenues a representative gas turbine plant would earn in the PJM energy and ancillary services

¹⁴⁹ Proposed Operating Agreement, Schedule 1, section 3.2.3A.02(b)(ii)(D).

¹⁵⁰ Proposed Operating Agreement, Schedule 1, section 3.2.3A.02(b)(ii).

¹⁵¹ Proposed Operating Agreement, Schedule 1, section 3.2.3A.02(c).

¹⁵² See Hogan & Pope PJM ORDC Report at 8-9.

markets given the actual market results from immediately prior years.¹⁵³ Those estimated EAS revenues calculated from actual market prices offset the gas plant's estimated Cost of New Entry ("CONE"), producing the Net CONE used to set the demand curve (i.e., the Variable Resource Requirement Curve) that is used to clear capacity auctions. A higher EAS Revenue Offset will reduce Net CONE.

Whether (and to what extent) a lower Net CONE in turn reduces capacity auction clearing prices could depend on a variety of factors. The EAS Revenue Offset was designed with a historical estimating approach so that energy and capacity markets work together over the long term, and was not designed to predict with certainty any particular year's energy market revenues. In other words, given that Capacity Resources are typically long-term assets, the EAS Revenue Offset calculated and used in the capacity auction for any given Delivery Year is not intended to necessarily match the actual revenues received by a given resource in the energy and ancillary service markets in that specific Delivery Year. Rather, the historic approach is utilized so that the actual revenues received by resources participating in the energy and ancillary service markets are used to offset capacity revenues in future years, such that over the long term, the combination of the revenues from all markets are recognized without actually matching them year-for-year. This approach was consciously chosen with the knowledge that any predictions of actual future year EAS revenues will be inherently wrong and therefore using actual historic revenues received was a better solution even given the timing mismatch between the years when the actual EAS revenues are received and the future capacity revenues are realized. Therefore, under the Tariff, the EAS Revenue Offset is estimated using three years of historic data on energy market prices and fuel costs. Any changes to energy prices from this reserves market

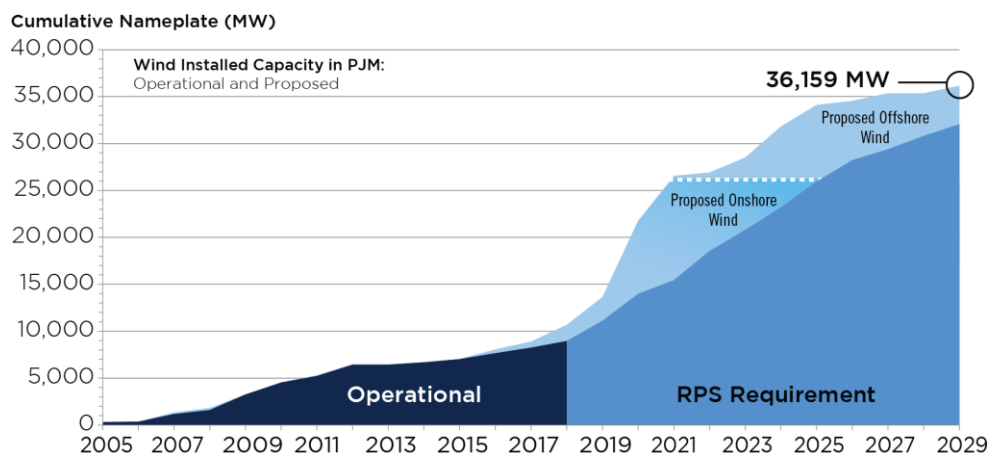
¹⁵³ Tariff, Attachment DD, section 5.10.

pricing proposal would be reflected in the historic data as those changes actually occur in the energy and ancillary service markets. This is precisely the manner in which the EAS Revenue Offset is designed to work, such that actual market results are used to determine the value of the offset used in any given RPM Auction. Therefore, PJM is not proposing any changes to the rules in this regard.

8. *PJM's proposed reforms will incentivize the development of flexible resources.*

The comprehensive reforms set forth in this proposal will incentivize the development of flexible resources, which will be essential to PJM in the coming years given the projected increase in variable resources in the PJM Region. As described in the Keech Affidavit,¹⁵⁴ in PJM, wind generation alone is projected to grow by approximately 360 percent over the next 10 years.

Figure 9. Projected Growth of Wind Resources in PJM



¹⁵⁴ See Keech Aff. ¶ 48.

This is consistent with Dr. Hogan and Dr. Pope who note that, “[a]s intermittent energy production increases, it will increase the frequency with which PJM will need to direct resources to ramp up or down to balance the system’s net load and maintain required levels of reserves.”¹⁵⁵

PJM’s proposal will encourage the development of flexible resources in three primary ways. First, PJM’s proposal to consolidate the Tier 1 and Tier 2 reserve products into one uniform Synchronized Reserve product will resolve key structural impediments to further investment in flexible resources that exist today solely by virtue of the current bifurcated structure. Specifically, PJM currently looks to Tier 1 MWs first when lining up reserves (because they are considered “free”) and then fills any remaining MWs needed to meet the Synchronized Reserve Requirement with Tier 2. In many instances, there are enough estimated “free” Tier 1 MWs on the system (many of them currently-operating inflexible resources) to negate the need to procure any Tier 2 MWs.¹⁵⁶ This discrepancy in price and usage between the two products has the effect of limiting the opportunities for more flexible resources that today would fall into the Tier 2 category from being utilized. Under PJM’s proposal, the unified Synchronized Reserve product would eliminate this discrepancy by valuing all Synchronized Reserves (including what is today considered “free” Tier 1) and their use equally, thereby enhancing the price signal for developers to invest in resources that are flexible to compete in the new combined reserve market.

Second, while the capacity market procures capacity on a forward basis for a target Delivery Year, the capacity market itself does not ensure that flexible resources will be procured, as it is, by design, resource agnostic. Thus, the energy and ancillary service markets should

¹⁵⁵ Hogan & Pope PJM ORDC Report at 7.

¹⁵⁶ See 2018 State of the Market Report at 455-56 (finding that “[i]n the RTO Zone, an average of 1,728.7 MW of tier 1 was available (Table 10-7) fully satisfying the synchronized reserve requirement in 50.3 percent of intervals”).

include pricing signals to incentivize flexibility. Since energy and ancillary service (reserve) revenues are deducted directly from the determination of CONE which impacts the clearing price in the capacity market, one of the aggregate effects, although not an explicit goal, of PJM's proposal will be to move certain revenues out of the capacity market and into reserve market prices. This effect of more revenues being collected in reserve markets, coupled with the enhanced opportunities for flexible resources to provide Synchronized Reserve, as described above, will send a more refined "flexibility" price signal to developers, representative of the increased value of flexible units that are able to respond quickly as reserves.

Third, with the addition of the sloped ORDCs that value reserves beyond the MRR at a non-zero value, units will be incentivized to invest in flexibility to qualify to provide both 10-minute and 30-minute reserves. Only resources that can ramp up within 10 or 30 minutes would be eligible for the additional reserve revenue available for providing the corresponding reserve products on the system.

C. Day-ahead and Real-time Markets Should Offer the Same Reserve Products.

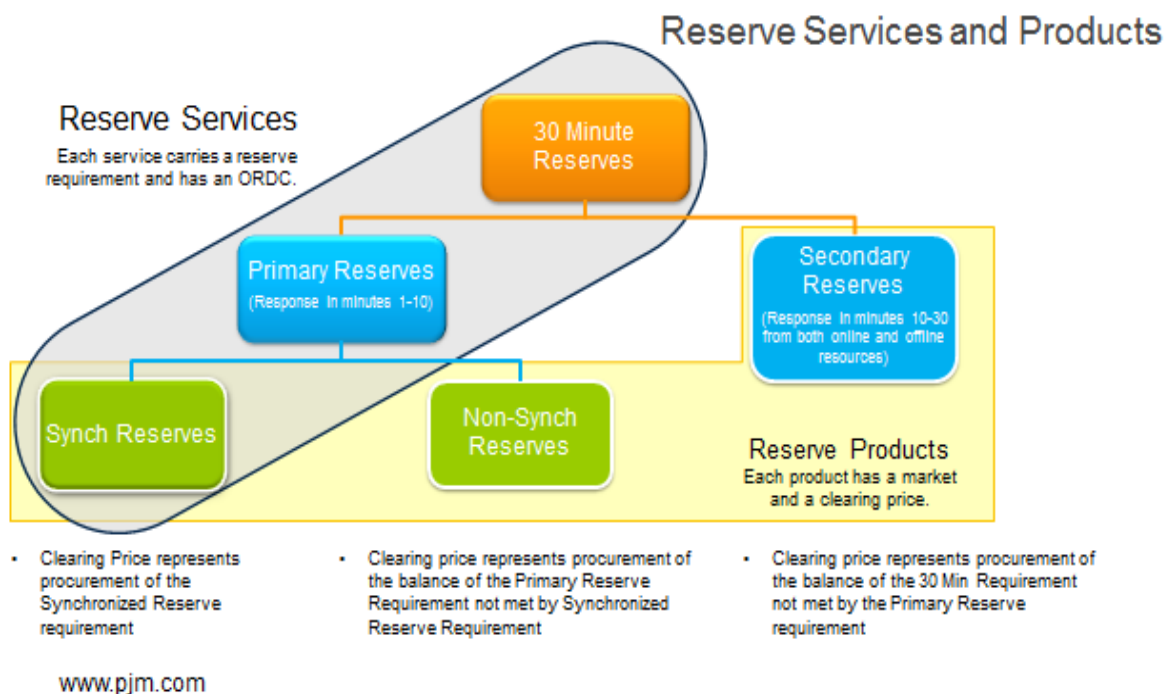
As explained in section II.C. above, PJM's forward procurement of its reserve products is inadequate. PJM's believes that the most appropriate solution to this problem is to align the day-ahead and real-time reserve markets—i.e., procure the same reserve products to meet the same reserve requirements both day-ahead and in real-time. This simple solution solves many different problems with the current market design for reserves. Aligning the day-ahead and real-time reserve markets in PJM will:

1. Ensure that PJM has a forward procurement process for all reserve products needed in real-time, which puts PJM on par with other ISOs/RTOs;
2. Ensure that PJM is truly minimizing the procurement costs of all its reserves by considering all product-specific requirements during the commitment of units for the next Operating Day;

3. Eliminate potential modeling discrepancies that can arise between the day-ahead and real-time energy and reserve markets simply because the reserve markets differ. This can create price dislocations created solely by the inconsistent modeling of reserve needs between markets that can create revenue streams for virtual trading but cannot be converged by them; and
4. Establish the incentives to perform in real-time when a forward reserve commitment is accepted. Resources scheduled reserves in the day-ahead market will be required to “buy out” of their position in real-time in an identical manner to what is done for energy today.

The resulting design is depicted in Figure 10 below.

Figure 10. PJM’s Proposed Reserve Services and Products



As explained above, the misalignment of the reserve markets creates modeling discrepancies and inefficiencies in operations and market outcomes because (1) the resource commitment from the day-ahead reserve market does not align with real-time needs; (2) it creates divergence in prices and congestion; and (3) creates opportunities to profit using virtual trading without the ability to converge the markets. The aforementioned issues exist today because of the misaligned markets and need to be addressed. While good market design alone

calls for aligning the markets, implementing PJM's proposed ORDCs will exacerbate the existing discrepancies, if not resolved, as PJM would procure more reserves through the market than it does under the current vertical, step-down ORDC.

Accordingly, now is the time to align the reserve markets. To do so, PJM proposes to amend its market rules to procure, in both the day-ahead and real-time markets, one 30-minute reserve product (Secondary Reserve) and two 10-minute reserve products (Synchronized and Non-Synchronized Reserve). Specifically, PJM proposes to add the 10-minute reserve markets to the day-ahead market, and the 30-minute reserve market to the real-time market. All reserve products will be procured using ORDCs based on the principles discussed above and using PJM's joint co-optimization algorithm to achieve the least-cost solution. To minimize modeling differences between the day-ahead and real-time markets, for each reserve product, PJM will use the same ORDCs (that is, they will be modeled upon the same uncertainties and uncertainty time horizons) in both markets. There may be small deviations in the minimum reserve requirements from day-ahead to real-time due to the fact that size of the largest system contingency (the driver behind the minimum reserve requirement) will potentially be different between day-ahead and real-time and possibly change throughout the operating day in real-time. Notwithstanding that minor difference, the curves will be calculated identically.

Adding the 10-minute reserve products to the day-ahead market will foster more efficient price formation in the day-ahead markets because it will consistently and transparently reflect the real-time need for reserves during the day-ahead commitment and pricing processes. This will move day-ahead prices closer to what can be expected under real-time operations (all other things equal) because the markets are aligned whereas today they are not. Additionally, adding the 10-minute reserve product to the day-ahead market will provide for a more optimal

commitment for 10-minute reserves because it will be assigned as part of a least-cost co-optimization that clears all energy and reserve needs simultaneously using a full unit commitment of all available resources. In addition to the market benefits, this more comprehensive and optimal commitment process will help ensure that real-time reserves in PJM are consistently adequate even to a greater extent than what is already done today.

Further, adding a 30-minute reserve product to the real-time market will ensure that PJM system operators can rely on the flexibility inherent in a 30-minute product to systematically (1) respond to various forecast errors (e.g., load, wind, solar, and net interchange), (2) backfill the 10-minute reserve requirement in the event such reserves are called upon, and (3) recover from larger losses of resources that could result from a contingency on the interstate natural gas pipeline system.¹⁵⁷ While Day-ahead Scheduling Reserves provide these benefits today, that there is no requirement to these reserves in real-time makes such benefits somewhat illusory. Thus, as discussed in more detail below, PJM proposes to require all resources that have accepted a commitment of 30-minute reserves in the day-ahead market to balance out of that position in real-time. This two-settlement process is virtually identical to what is performed in the energy market and is also being proposed for 10-minute reserves. The financial obligation resulting from the day-ahead market assignment and the requirement to buy out of that position in real-time if a resource comes up short on its position will ensure that these benefits will be more tangible.

Complementing the alignment of the day-ahead and real-time markets, PJM is proposing to strengthen the rules for procuring reserves, as described in more detail below. These market rules will address concerns about withholding reserve capability, ensuring sellers are properly

¹⁵⁷ See Pilon Aff. ¶¶ 28-29.

compensated for reserves they actually provide in real-time, requiring sellers to pay for any reserves they fail to provide, and making sellers whole when following PJM's dispatch instructions would not otherwise be in the seller's financial interest.

While aligning the real-time and day-ahead markets to procure all three reserve products in both markets conceptually is a big step forward in market design, the existing market rules for Synchronized Reserve and Non-Synchronized Reserve provide a very good model for integrating Secondary Reserve into the real-time market, and minimal changes are required to procure Synchronized Reserve and Non-Synchronized Reserve on a day-ahead basis. By contrast, the tariff revisions required to strengthen the market rules so as to achieve the over-arching objective of this filing—ensuring reserves are properly valued in the market for the benefits they provide—are very detailed, as discussed below. The proposed changes strengthen PJM's market rules to ensure achieving the objective of properly valuing reserves in the markets for the benefits they provide. All references to sections in the text are intended to refer to sections of the Operating Agreement, Schedule 1 and the identical provisions of the Tariff, Attachment K-Appendix.

1. *PJM modeled the market rule changes to implement Secondary Reserves in both the day-ahead and real-time reserve markets on the rules for Synchronized and Non-Synchronized Reserves.*

To add the 30-minute Reserve Requirement to the real-time market, PJM first proposes to rename the current Day-ahead Scheduling Reserve product as Secondary Reserve, and updating all tariff references to reflect this name change.¹⁵⁸ Because Secondary Reserve will now have a performance obligation and will be procured in the same general manner as Synchronized Reserve and Non-Synchronized Reserve, PJM is adding new market rules describing Secondary

¹⁵⁸ See e.g., proposed Operating Agreement, Schedule 1, sections 1.5A, 1.7, 1.10, 1.11, 2.5, 3.2.

Reserve and providing for the clearing of Secondary Reserve based on those for Synchronized Reserve and Non-Synchronized Reserve.

Specifically, PJM is adding a new section within section 1.7 “General,” alongside the provisions describing generally Synchronized Reserve and Non-Synchronized Reserve. New section 1.7.19A.02 describes, in subsection (a), the types of resources eligible to provide Secondary Reserve; subsection (b) requires PJM to obtain and maintain sufficient Secondary Reserves (plus Synchronized and Non-Synchronized Reserves) to meet the 30-minute reserve objectives for each applicable Reserve Zone and Reserve Sub-zone; and subsection (c) provides that a resource’s Secondary Reserve capability is its ability to increase energy or reduce demand within 30 minutes, minus its ability to increase energy or reduce demand within 10 minutes. That is, Secondary Reserve is the remainder of the capability a resource can provide within 30 minutes, after accounting for its capability to provide Synchronized Reserve or Non-Synchronized Reserve. This new section generally mirrors sections 1.7.19A(a)-(c) and 1.7.19A.01(a)-(c) which set forth the same requirements applicable to Synchronized Reserve and Non-Synchronized Reserve, respectively.

PJM also is adding rules to schedule and dispatch Secondary Reserve in new section 1.11.4C. Again, PJM proposes to use the existing provisions for Synchronized Reserve in section 1.11.4A as a model. Thus, just like for Synchronized Reserve, the new section for clearing Secondary Reserve provides that Market Buyers with a Secondary Reserve Obligation (i.e., load-serving entities) can satisfy this obligation by contract or through purchases in the market.¹⁵⁹ This rule is nearly identical to the rules for Synchronized and Non-Synchronized

¹⁵⁹ Proposed Operating Agreement, Schedule 1 section 1.11.4C(a). Proposed Operating Agreement, Schedule 1, section 1.11.4C(c) provides the basic rule that PJM will dispatch resources for Secondary Reserve and sellers of dispatched resources will comply with such instructions.

Reserve.¹⁶⁰ The actual methodology for clearing these reserve products is discussed in section III.C.8 below.

Similarly, PJM is proposing to overhaul the rules for Day-ahead Scheduling Reserve governing offers (in section 1.10.1A(j)), charges and credits (in section 3.2.3A.01), and market clearing prices (also in section 3.2.3A.01) to align such rules with the provisions for Synchronized Reserve. All of these revisions are substantively discussed below.

However, the provisions for Secondary Reserve distinctly diverge from those for Synchronized Reserve in two substantive respects. First, offline resources can provide Secondary Reserve, while resources must be online (i.e., synchronized to the grid) to provide Synchronized Reserve. Second, PJM is proposing that the non-performance penalty for Secondary Reserve apply only when PJM dispatches an offline generation resource for energy and it fails to come online within 30 minutes or reduces a demand response resource for energy and it fails to reduce load.¹⁶¹ In other words, the non-performance assessment will apply if a generation resource has a Secondary Reserve commitment during an Operating Day, and PJM calls upon that resource to provide energy at a later point in the day but the resource fails to provide energy at least equal to its Economic Minimum megawatt level. If this occurs, then PJM will set such resource's real-time Secondary Reserve assignment to zero for the period on that Operating Day starting with the later of (1) the beginning of the Operating Day, or (2) the last time the resource came offline, and ending with the time in which the resource failed to perform.¹⁶² By setting the real-time assignment to zero the resource will not be paid for any real-time Secondary Reserve during these intervals, and will be required to "buy out" (i.e., replace)

¹⁶⁰ See proposed Operating Agreement, Schedule 1, sections 1.11.4A(c), 1.11.4B(c).

¹⁶¹ See proposed Operating Agreement, Schedule 1, section 3.2.3A.01(h).

¹⁶² Proposed Operating Agreement, Schedule 1, section 3.2.3A.01(h)(i).

any day-ahead Secondary Reserve commitments during these intervals at the applicable Real-time Secondary Reserve Market Clearing Price.

The same general rule applies to demand response resources providing Secondary Reserve, except, because such resources generally lack real-time telemetry, PJM will not know whether the resource actually reduced load until the next Operating Day and could continue to assign the resource to provide reserves when it is not physically able to provide them.¹⁶³ To account for this difference, PJM will set the resource's real-time Secondary Reserve assignment to zero for the period starting at the later of (1) the last time the resource successfully reduced load or (2) the beginning of the Operating Day and ending at the earlier of (i) the next time the resource actually reduces load in accordance with dispatch or (ii) the end of the Operating Day.¹⁶⁴ The resource will not be paid for any real-time Secondary Reserve during this period, and will need to buy replacement megawatts for any day-ahead Secondary Reserve commitment the resource had during this period.

2. *PJM is proposing a tariff mechanism to procure Synchronized Reserve and Non-Synchronized Reserve in the day-ahead reserve markets.*

To procure Synchronized Reserve and Non-Synchronized Reserve on a day-ahead basis, PJM is proposing to revise the "Dispatch" provisions pertaining to Synchronized Reserve and Non-Synchronized Reserve in sections 1.11.4A and 1.11.4B, respectively. In subsection (b) of both sections, PJM is proposing to add language similar to that in new section 1.11.4C(b) requiring PJM to clear both the Day-ahead and Real-time Synchronized and Primary Reserve

¹⁶³ PJM is retaining the existing Day-ahead Scheduling Reserve rules for measuring and verifying performance by demand response resource, but is moving them from section 3.2.3A.01(c)(iii) and consolidating them with the Secondary Reserve penalty provisions in section 3.2.3A.01(h)(ii). PJM is also retaining the measurement and verification provisions for Batch Load Economic Load Response Participant Resources, but proposes to also move these provisions Secondary Reserve penalty provisions in section 3.2.3A.01(h)(iii) from current section 3.2.3A.01(d)(iv).

¹⁶⁴ Proposed Operating Agreement, Schedule 1, section 3.2.3A.01(h)(ii).

Markets using the new ORDCs, based on the submitted offers.¹⁶⁵ Like Secondary Reserve, PJM is proposing to cap the amount of demand response resources that can be procured to meet the Synchronized Reserve Requirement at 50 percent of the Minimum Synchronized Reserve Requirement.¹⁶⁶

While these are the operative revisions to require PJM to obtain Synchronized Reserve and Non-Synchronized Reserve day-ahead, additional tariff revisions are necessary to fully align the two markets, compensate cleared resources, and generally treat reserves more like energy. These revisions are discussed in detail below.

3. *PJM proposes to clarify and make explicit the reserve must-offer requirements for all Capacity Resources.*

Currently, all online generation resources with Synchronized Reserve capability “are deemed to be available” to provide Tier 1 Synchronized Reserve, and this requirement extends “to the capacity resource’s capability to provide these services.”¹⁶⁷ In this filing, PJM proposes to make this “must-offer” requirement for Capacity Resources and online generation resources more explicit and extend it to cover Secondary Reserve and not only Synchronized and Non-Synchronized Reserves. Moreover, applying such must-offer requirements to reserves in addition to energy furthers the development of efficient markets, as reserves and energy should be substitutable with the resource indifferent as to which it provides.

Thus, to ensure proper price formation in the reserve markets and prevent withholding of reserve capability, during the stakeholder process, PJM, in conjunction with the IMM, developed

¹⁶⁵ PJM is also proposing to clarify the process for clearing the reserve markets, as discussed in section III.C.8 below.

¹⁶⁶ Proposed Operating Agreement, Schedule 1, section 1.11.4A(b). Because demand response resources are incapable of providing Non-Synchronized Reserves, PJM is not proposing a similar cap on the quantity of demand response resources that can be procured to meet the Primary Reserve Requirement.

¹⁶⁷ Operating Agreement, Schedule 1, section 1.7.19A(a).

a more explicit reserve must-offer requirement.¹⁶⁸ Specifically, PJM proposes to clarify that all Generation Capacity Resources¹⁶⁹ must offer all available reserve capability at all times, regardless of whether the resource is online or offline.¹⁷⁰ This requirement is based on the energy must-offer requirement for Generation Capacity Resources in section 1.10.1A(d).

While non-capacity generation resources do not have a strict must-offer requirement like Capacity Resources, the current market rules deem such resources that are capable of providing reserves as having offered all their available reserve capability for each interval they offer to supply energy,¹⁷¹ and PJM proposes to continue such practice but with clarifications.¹⁷² Indeed, PJM proposes to continue its practice allowing resources that can reliably provide reserves, but which PJM is unable to assess their reserve capability, like hydroelectric and storage resources (as PJM does not know their water or battery levels), to submit reserve offers with a stated megawatt level in order to participate in the Synchronized Reserve market and to comply with the must offer requirement.¹⁷³

However, not all generation resources are capable of reliably providing reserves, and these resource types are exempt from the must-offer requirement. Stated another way, resources that cannot be depended on to provide a specified quantity of energy within 10 minutes or 30

¹⁶⁸ See PJM Interconnection, L.L.C., *Proposal for Must Offer Requirements* (Oct. 12, 2018), <https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20181012/20181012-item-07a-sr-must-offer-requirements.ashx>.

¹⁶⁹ Generation Capacity Resources include Capacity Storage Resources.

¹⁷⁰ See proposed Operating Agreement, Schedule 1, sections 1.10.1A(j)(i)(1) (Generation Capacity Resource must-offer requirement to supply Synchronized and Non-Synchronized Reserves) and 1.10.1A(m)(i)(1) (Generation Capacity Resource must-offer requirement to supply Secondary Reserve).

¹⁷¹ See Operating Agreement, Schedule 1, sections 1.7.19A(a), 1.7.19A.01(a).

¹⁷² See proposed Operating Agreement, Schedule 1, sections 1.10.1A(j)(i)(2) (market rule deeming online non-capacity resources as offering to supply their Synchronized Reserve and Non-Synchronized Reserve capability), 1.10.1A(m)(i)(2) (market rule deeming available non-capacity resources as offering to supply their Secondary Reserve capability).

¹⁷³ See proposed Operating Agreement, Schedule 1, sections 1.10.1A(j)(i)(2) (for the ability to submit offer MWs), 1.10.1A(j)(i)(1) (for the must-offer portion); see also proposed Operating Agreement, Schedule 1, sections 1.10.1A(m)(i)(1), 1.10.1A(m)(i)(1), 1.10.1A(m)(i)(2) (pertaining to Secondary Reserve).

minutes on a consistent basis will not be required to offer reserves. Accordingly, the must-offer requirement applies only to resources “capable of providing” Synchronized, Non-Synchronized, and Secondary Reserves.¹⁷⁴ For this reason, PJM is proposing not to automatically consider certain generation resource types (nuclear, wind, and solar) as available to provide reserves when they submit offers for energy, unless they notify PJM that the specific resource can reliably provide reserves.¹⁷⁵

This is consistent with PJM’s current and well-established practice. PJM has long excluded from its Tier 1 Synchronized Reserve determinations those resource types that “cannot reliably provide Synchronized Reserve,” including nuclear, wind, solar, energy storage resources, and hydro units.¹⁷⁶ However, PJM currently allows sellers of these resource types provide Tier 1 Synchronized Reserve if the seller notifies PJM that the specific resource is able to reliably provide the reserve so they may be included in the reserve estimates by exception.¹⁷⁷

4. *PJM proposes to reduce reliance on reserve offer prices and rely primarily on the cost of committing the resource for reserves instead of energy.*

Under the current tariff, the offer price to supply reserves generally is not the determinative factor in determining whether a specific resource clears a reserve market; rather, the resource’s specific opportunity cost of providing reserves instead of energy (i.e., the

¹⁷⁴ See proposed Operating Agreement, Schedule 1, sections 1.10.1A(j)(i)(1) (Generation Capacity Resource must-offer requirement to supply Synchronized and Non-Synchronized Reserves) and 1.10.1A(m)(i)(1) (Generation Capacity Resource must-offer requirement to supply Secondary Reserve).

¹⁷⁵ See proposed Operating Agreement, Schedule 1, sections 1.10.1A(j)(i)(2), 1.10.1A(m)(i)(2).

¹⁷⁶ PJM, *Manual 11: Energy & Ancillary Services Market Operations*, § 4.2.1 (rev. 104, Feb. 7, 2019), <https://www.pjm.com/~media/documents/manuals/m11.ashx>.

¹⁷⁷ *Id.*

difference between the resource's energy offer and the applicable LMP) dictates whether it is assigned a reserve commitment.¹⁷⁸

Indeed, while the current market rules do not apply a dollar cap on offers to provide Day-ahead Scheduling Reserve (now replaced by Secondary Reserve), opportunity cost is one of two factors in scheduling Day-ahead Scheduling Reserve.¹⁷⁹ Further, the tariff requires that “[a]ll Non-Synchronized Reserve offers shall be for \$0.00/MWh;”¹⁸⁰ thus, prohibiting any offer price. For Synchronized Reserve, however, sellers are permitted to submit offers up to a level equal to the resource's “variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.”¹⁸¹

In this filing, PJM proposes to reduce reliance on reserve offer prices further and more explicitly rely on product substitution and opportunity costs for committing and pricing resources, respectively. For Secondary Reserve, PJM proposes to remove the ability to submit a stated offer price, and instead such offers for the supply of Secondary Reserve will be at \$0.00/MWh.¹⁸² For Non-Synchronized Reserve, PJM proposes to maintain offer prices at \$0.00/MWh, but move this rule from section 1.7.19A.01, which generally describes the Non-Synchronized Reserve product and eligibility to provide it, to new section 1.10.1A(j)(i), which details offers to provide 10-minute reserves by generation resources.¹⁸³

¹⁷⁸ See Operating Agreement, Schedule 1, sections 1.11.4A(b), 1.11.4B(b), 1.10.1A(m).

¹⁷⁹ See Operating Agreement, Schedule 1, section 1.10.1A(m) (“Market Sellers providing Day-ahead Scheduling Reserves Resources shall submit in the Day-ahead Scheduling Reserves Market: 1) a price offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s).”).

¹⁸⁰ Operating Agreement, Schedule 1, section 1.7.19A.01(e).

¹⁸¹ Operating Agreement, Schedule 1, section 1.10.1A(j).

¹⁸² See proposed Operating Agreement, Schedule 1, section 1.10.1A(m)(i)(3).

¹⁸³ See proposed Operating Agreement, Schedule 1, section 1.10.1A(j)(i)(4).

However, PJM proposes to eliminate consideration of opportunity costs in pricing and compensating offline resources and synchronous condensing resources.¹⁸⁴ As part of the process leading to this proposal, PJM scrutinized every aspect of the reserve markets, and one thing PJM found was that the LMP available while a resource is offline is not a reasonable proxy for the energy market revenues (above cost) the resource could have earned—and thus not a reasonable representation of their opportunity cost. It is often the case that the resource is offline and available for reserves, rather than online providing energy, because it is not economic to provide energy once the resource’s fixed costs (e.g., startup and no load costs) and the impact to production cost and prices resulting from the commitment of that resource were considered.¹⁸⁵ Simply put, in this instance an offline resource does not have an opportunity cost, because the resource would not have been dispatched in economic merit in order to provide energy regardless of whether or not it was needed for reserves. Moreover, in real-time, offline resources cannot physically capture the five-minute energy market LMP upon which opportunity cost is based, as they cannot startup quickly enough to capture the profit from such energy price.¹⁸⁶ As a result, there is no opportunity cost to consider as part of an offer to provide Non-Synchronized Reserve or Secondary Reserve if the resource is offline or as part of an offer to provide Synchronized Reserve or Secondary Reserve for a resource in synchronous condensing mode, in the pricing

¹⁸⁴ PJM’s proposed changes to the compensation rules are discussed in section III.C.12 below.

¹⁸⁵ PJM explained this to stakeholders at the March 14, 2019 EPFSTF meeting. PJM Interconnection, L.L.C., *Reserve Markets Enhancements Filing Summary*, at 14-21 (Mar. 14, 2019), <https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20190314-pf/20190314-pjm-filing-summary.ashx>.

¹⁸⁶ Despite limiting Non-Synchronized Reserve offers to \$0.00/MWh and not considering opportunity costs, clearing prices in the Non-Synchronized Reserve markets should be above zero. In fact, PJM’s simulations show that the clearing price may range from \$1.26/MWh to \$3.97/MWh. See Keech Aff. ¶ 43, Table 5. This results from clearing Non-Synchronized Reserves based on the ORDC which values reserves based on the probability of falling below the minimum reserve requirement.

and settlement of such markets.¹⁸⁷ PJM therefore proposes to discontinue the practice of including opportunity costs for offline resources and synchronous condensers in pricing and settling the reserve markets.

For Synchronized Reserve, PJM is proposing to retain that offers price “must be cost-based.”¹⁸⁸ But, as explained in Section III.A, above, PJM proposes to replace cost cap based on inclusion of variable operating and maintenance costs in their Synchronized Reserve offers and a \$7.50 adder. Variable operating and maintenance costs are not properly recovered through the provision of Synchronized Reserve, where the resource stands ready to provide additional energy if called upon, but rather are properly recovered through resource’s energy market offers. For the reasons stated above in section III.A, the \$7.50 adder is no longer appropriate and should not be included in Synchronized Reserve offers. It was adopted as an incentive to supply reserves, as it provided “reasonable profit margin” and was based on offers to supply 10-minute reserves before the 2002 implementation of PJM’s current Synchronized Reserve market.¹⁸⁹ Such incentive is no longer necessary, nor grounded in the current market.

In place of these two factors, PJM proposes to add a cap on the costs that may be included in a Synchronized Reserve offer up to the “expected value of the penalty for failing to provide Synchronized Reserve,”¹⁹⁰ where the expected value of the penalty is “the product of: (A) the average penalty, expressed in \$/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a

¹⁸⁷ Similarly, there is no opportunity cost to consider as part of an offer to provide Secondary Reserve by an offline generation resource.

¹⁸⁸ See proposed Operating Agreement, Schedule 1, section 1.10.1A(j)(i)(3).

¹⁸⁹ See *PJM Interconnection, L.L.C.*, 101 FERC ¶ 61,115, at P 8 & n.6 (2002); PJM ER02-2519 Filing at 10-13.

¹⁹⁰ See proposed Operating Agreement, Schedule 1, section 1.10.1A(j)(i)(3).

Synchronized Reserve event that will qualify for non-performance assessments will occur.”¹⁹¹ PJM will post this value on its website and will update it annually.

However, because this value is based on historical data and may not be reflective of market conditions under the new paradigm, PJM is proposing to state a starting value in the tariff of \$0.02/MWh, which, as Mr. Keech explains,¹⁹² is based on data from the 2018 calendar year, and to recalculate that value monthly, using data from the date of implementation through the prior month, until the second January 1 following the implementation date.¹⁹³ This process ensures that the Synchronized Reserve offer cap reflects the market dynamics.

It also bears noting that PJM is proposing two changes to the current penalty for non-performance in a Synchronized Reserve Event, as set forth in section 3.2.3A(j). One, while PJM is not proposing to change the structure of the penalty, including keeping its retroactive refund aspect,¹⁹⁴ PJM is proposing to cap the megawatts used to determine the amount of the retroactive refund at the lesser of the resources actual real-time assignment in those prior intervals or the amount of megawatts the resource failed to provide during the Synchronized Reserve Event. Two, with the addition of the Day-ahead Synchronized Reserve Market, PJM is proposing to specify that the Real-time Synchronized Reserve Market Clearing Price shall be used to calculate

¹⁹¹ See proposed Operating Agreement, Schedule 1, section 1.10.1A(j)(i)(3).

¹⁹² Keech Aff. ¶ 55-58.

¹⁹³ See proposed Operating Agreement, Schedule 1, section 1.10.1A(j)(i)(3).

¹⁹⁴ As stated in the current market rules, the penalty requires a resource that fails to respond in response to a Synchronized Reserve Event to refund Synchronized Reserve revenues “for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event.” Operating Agreement, Schedule 1, section 3.2.3A(j).

the penalty since Synchronized Reserve will now be cleared in both the day-ahead and real-time markets.¹⁹⁵

These changes to the offer prices for the three reserve products allow a resource's offer to supply energy be the determinative factor in whether a resource is cleared to supply reserves or energy, and make the resource indifferent as to which it provides, as the clearing process will still consider any revenue forgone in the energy market when providing reserves. The process for clearing reserves is discussed section III.C.8 below.

5. *PJM proposes to determine the available reserve capability of most generation resources.*

PJM proposes to extend its current practice of determining each resource's available capability to provide Tier 1 Synchronized Reserve based on the resource's energy offer parameters to now determine each resource's available capability to provide Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, for both the day-ahead and real-time reserve markets. PJM proposes to determine the available reserve capability of all Generation Capacity Resources¹⁹⁶ and non-capacity resources participating in the energy markets, and make such determinations largely based on the resource's energy market offer.¹⁹⁷

Currently, asset owners must maintain two sets of offer data, energy market offer data and reserve market offer data, which are intended to reflect the ramping capability of a resource. PJM's analysis of under-response during Synchronized Reserve events has shown that the reserve market data is not maintained as accurately as energy market offer data, which leads to imprecise assessments of available reserve capability. If a resource can perform in the energy

¹⁹⁵ The current penalty applies only to Tier 2 Synchronized Reserve resources, but, with the elimination of the two tiers of Synchronized Reserve, it will now apply to all resources assigned or self-scheduled to provide Synchronized Reserve but fail to perform. See proposed Operating Agreement, Schedule 1, section 3.2.3A(j).

¹⁹⁶ See proposed Operating Agreement, Schedule 1, sections 1.10.1A(j)(ii), 1.10.1A(m)(ii).

¹⁹⁷ *Id.*

market consistent with the ramp rate specified in the energy offer parameters, it follows that the resource should be able to perform in the reserve market consistent with that same ramp rate since fulfillment of the reserve obligations means providing energy when called upon. Separate offers for reserves are therefore generally superfluous.¹⁹⁸ Using energy market offer data to determine reserve capability will therefore improve accuracy of reserve measurements. Additionally, this assists with adherence to and enforcement of the must-offer requirement, as it reduces the opportunity for a resource to unintentionally withhold reserve capability from the market.

However, PJM would not make such determination for resource classes for which PJM would not be as able to reliably calculate their available megawatt capability for reserves (e.g., hydro, storage, and demand response resources) given lack of transparency into other factors that govern their capability to provide reserves (such as water levels, state of charge and which processes are being curtailed in order to provide load reduction); rather, sellers of such resources may submit offers specifying a specific quantity of reserves the resource is capable of reliably providing as Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.¹⁹⁹ In fact, if the resource is subject to the must-offer requirement, it must do so.

PJM is proposing separate rules for how it would determine a resource's available capability to provide Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve. For Synchronized Reserve from resources providing energy, the determination is "based on the resource's current performance and initial energy output and the following offer

¹⁹⁸ As discussed below, PJM is proposing that resources may be able to specify its maximum reserve capability (for both Synchronized and Secondary Reserve) to the extent such maximum value differs from the resource's maximum energy capability (i.e., its Economic Maximum).

¹⁹⁹ See proposed Operating Agreement, Schedule 1, sections 1.10.14(j)(ii), 1.10.1A(j)(iii), 1.10.1A(j)(iv), 1.10.1A(m)(ii), 1.10.1A(m)(iii).

parameters submitted as part of the resource's energy offer: (A) ramp rate; and (B) the lesser of Economic Maximum and Synchronized Reserve maximum."²⁰⁰ In other words, PJM will look at the resource's current energy position, and then calculate how much more energy the resource can produce based on its submitted ramp rate and Economic Maximum. However, some resource's may have an operating configuration that prevents it from reliably providing Synchronized Reserves up to its Economic Maximum (such as duct burners which are used to provide the megawatts at the top of the resource's dispatchable range, and which require additional time to transition into that range), and PJM proposes to allow sellers to set a Synchronized Reserve maximum offer parameter that is lower than its Economic Maximum only upon the seller justifying to PJM such lower value.

The determination of available Non-Synchronized Reserve capability is similar to that for Synchronized Reserve, but because a resource must be offline (i.e., not currently synchronized to the grid) the determination does not start from the resource's current energy output. Accordingly, PJM will include the resource's startup time and notification time, in addition to its ramp rate and Economic Maximum (or Synchronized Reserve maximum MW if lesser), all as stated in the resource's energy offer parameters.²⁰¹

The determination of available Secondary Reserve capability generally follows the Synchronized Reserve approach for online generation resources,²⁰² the Non-Synchronized Reserve approach for offline resources,²⁰³ and for generation resources capable of synchronous condensing, PJM will also consider the resource's condense to generation time constraints, as

²⁰⁰ Proposed Operating Agreement, Schedule 1, section 1.10.1A(j)(ii)(2). For generation resources capable of synchronous condensing, PJM will also consider the resource's condense to generation time constraints, as stated in its energy offer. *Id.*

²⁰¹ Proposed Operating Agreement, Schedule 1, section 1.10.1A(j)(iii)(2).

²⁰² Proposed Operating Agreement, Schedule 1, section 1.10.1A(m)(ii)(2)(A).

²⁰³ Proposed Operating Agreement, Schedule 1, section 1.10.1A(m)(ii)(2)(B).

stated in its reserve offer.²⁰⁴ There is one substantive difference for all three cases, however. PJM will use “the lesser of Economic Maximum and Secondary Reserve maximum MW,”²⁰⁵ and not Synchronized Reserve maximum MW, in the determination.

6. *PJM is proposing to strengthen the rules for a resource’s offer parameters to ensure that PJM can properly evaluate a resource’s available reserve capability.*

As a general rule, for all resources capable of reliably providing reserves, PJM will be the party responsible for determining how much reserve a specific resource is offering in both the day-ahead and real-time reserve markets.²⁰⁶ The accuracy of PJM’s determination of available reserve capability is wholly dependent on the inputs provided by each resource’s offer parameters. The two primary parameters in these calculations are Economic Maximum and ramp rate. Thus, PJM is strengthening its market rules to require Market Sellers to “specify a ramping rate in the Offer Data that is an accurate representation of the resource’s capabilities given the confines of the PJM software.”²⁰⁷ PJM’s proposal recognizes certain limitations in its market software related to generation resource modeling. In fact, PJM’s market software does not allow the ramping capability of combined cycle units and units with duct firing ranges, among other configurations, to be perfectly modeled. Accordingly, the proposed rule allows for some modifications to a resource’s true ramp rate in order to accommodate the software. These revisions ensure that each resource will offer all its available ramping capability to the reserve

²⁰⁴ Proposed Operating Agreement, Schedule 1, section 1.10.1A(m)(ii)(2)(C).

²⁰⁵ Proposed Operating Agreement, Schedule 1, section 1.10.1A(m)(ii)(2)(A). The Secondary Reserve maximum MW offer parameter addresses the same issue as the Synchronized Reserve maximum MW offer parameter—it allows a resource with an operating configurations that prevent it from reliably providing Secondary Reserves up to its Economic Maximum to cap its available Secondary Reserve capability.

²⁰⁶ As noted, while hydroelectric, storage, and demand response resources are capable of reliably providing reserves, PJM will not be determining their available reserve capability.

²⁰⁷ Proposed Operating Agreement, Schedule 1, section 1.7.19.

(and energy) markets to the extent currently possible, and will prevent withholding of such energy and reserve capability through the submission of an intentionally incorrect ramp rate.

In addition, consistent with current market rules for Synchronized Reserve, PJM is proposing that offers to supply Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.²⁰⁸ Thus, PJM is proposing to add ramp rate, Synchronized Reserve maximum MW, and Secondary Reserve maximum MW to the list of offer parameters that a seller can update during the Operating Day²⁰⁹ and that a seller can vary for each clock hour.²¹⁰

7. *PJM proposes specific rules for demand response participation in reserve markets that recognize their characteristics.*

Demand response resources currently can offer to supply Synchronized Reserve and Day-ahead Scheduling Reserve,²¹¹ and PJM proposes to continue that practice under the new reserve market paradigm. PJM is proposing market rules specific for demand response resources to supply reserves. As a general matter, the must-offer requirements do not extend to demand response resources, and, consistent with current practice, PJM will not determine their available reserve capability. Rather, sellers that submit offers to reduce demand in the energy markets

²⁰⁸ See proposed Operating Agreement, Schedule 1, sections 1.10.1A(j)(i)(3), 1.10.1A(j)(i)(4), 1.10.1A(m)(i)(3).

²⁰⁹ Proposed Operating Agreement, Schedule 1, section 1.10.9A(b). In a corresponding change, PJM is proposing to remove ramp rate from the list of operating parameters that cannot be updated during the Operating Day. See proposed Operating Agreement, Schedule 1, section 1.10.9B(d).

²¹⁰ Proposed Operating Agreement, Schedule 1, sections 1.10.1A(d)(iii) and 1.10.9B(b).

²¹¹ See Operating Agreement, Schedule 1, sections 1.5A.8, 1.7.19A, 1, Definitions C-D (definition of Day-ahead Scheduling Reserve Resources). As noted, demand response resources are incapable of providing Non-Synchronized Reserve.

may submit offers to supply Synchronized Reserve and Secondary Reserve, in both the day-ahead and real-time reserve markets.²¹²

Just as under the current rules, such offers must equal or exceed 0.1 MW, include the required offer information, and may vary hourly and be updated up to 65 minutes before the applicable clock hour.²¹³ PJM is proposing that offers for Synchronized Reserve by demand response resources be subject to the same expected penalty value offer cap that applies to generation resources²¹⁴ and that offers to supply Secondary Reserve are set to \$0.00/MWh.²¹⁵

PJM is also proposing several clean-up changes. One, in developing this proposal, PJM observed that many of its existing market rules referred to “Demand Resources” as the resources that would provide reserves, and not resources of Economic Load Response Participants. Demand response resources can be both Demand Resources and Economic Load Response Participants resources. However, Demand Resources are Capacity Resources²¹⁶ and generally participate in PJM’s Emergency Load Response Program. To participate in the energy and ancillary services markets, sellers of demand response resources must register as Economic Load Response Participants.²¹⁷

Accordingly, to clarify the tariff and ensure all are on notice that Economic Load Response Participants resources are the resources that can provide reserves and not Demand Resources, PJM is proposing to refer only to Economic Load Response Participants resources in these proposed market rules.

²¹² See proposed Operating Agreement, Schedule 1, sections 1.10.1A(j)(iv), 1.10.1A(m)(iii).

²¹³ See proposed Operating Agreement, Schedule 1, sections 1.10.1A(j)(iv)(1), 1.10.1A(m)(iii)(1).

²¹⁴ See proposed Operating Agreement, Schedule 1, section 1.10.1A(j)(iv)(2).

²¹⁵ See proposed Operating Agreement, Schedule 1, section 1.10.1A(m)(iii)(2).

²¹⁶ See RAA, Article 1 (definition of Demand Resource).

²¹⁷ See Operating Agreement, Schedule 1, section 1.5A.3.

Two, the current market rules cap energy market offers submitted by Emergency Load Response and Pre-Emergency Load Response participants based on the Reserve Penalty Factors. As a result, maximum energy offers from such participants with a lead time of (1) 30 minutes are “\$1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement [\$850/MWh], minus \$1.00” or, simply stated, \$1,849/MWh; (2) 60 minutes are \$1,000/MWh plus half of that Reserve Penalty Factor or, simply stated, \$1,425/MWh; and (3) 120 minutes are \$1,100/MWh.²¹⁸ Given that PJM is proposing to raise the maximum Reserve Penalty Factors to \$2,000/MWh (and more broadly proposing dynamic penalty factors), PJM proposes to untether the energy market offers for such resources from the Reserve Penalty Factors, and simply state the equivalent dollar per megawatt-hour figures in the tariff.²¹⁹ Moving to stated prices is reasonable, as it does not change the actual price for such resources to be dispatched but it does ensure that the Reserve Penalty Factor properly captures the cost of all actions PJM would need to take to maintain reserves in excess of the minimum requirements.²²⁰ By contrast, maintaining the current energy offer caps based on the Reserve Penalty Factor would set the effective energy offer caps for some Emergency Load Response and Pre-Emergency Load Response participants well in excess of \$2,000/MWh and others at

²¹⁸ See Operating Agreement, Schedule 1, section 1.10.1A(d)(x)(a). The current posted PJM tariff does not show these provisions governing energy offer caps for Emergency Load Response and Pre-Emergency Load Response participants because PJM inadvertently removed them in a compliance filing of Order No. 831. See *PJM Interconnection, L.L.C.*, Order No. 831 Compliance Filing, Docket No. ER17-1567-000 (May 8, 2017); *PJM Interconnection, L.L.C.*, Compliance Filing Concerning Offer Cap Rule, Docket No. ER17-1567-001 (Dec. 11, 2017). However, these provisions are part of PJM’s filed rate and so PJM is not showing them in redline in the enclosed Operating Agreement revisions. PJM is only showing in redline the proposed changes to the energy market offer caps in proposed Operating Agreement, Schedule 1, section 1.10.1A(d)(x).

²¹⁹ See proposed Operating Agreement, Schedule 1, section 1.10.1A(d)(x).

²²⁰ See section III.B.1 (explaining the purpose of the \$2,000/MWh Reserve Penalty Factor).

\$2,000/MWh.²²¹ Such a result would be contrary to the design and purpose of the Reserve Penalty Factor.

8. *PJM proposes to update its reserve market clearing mechanisms to properly evaluate the comparative costs of committing a resource for energy or reserves.*

To clear Synchronized Reserve in both the day-ahead and real-time markets, PJM proposes to use the upgraded ORDCs discussed above, the offers submitted into the markets, including the offers determined by PJM based on the resource's energy offer parameters, and "the product substitution cost between providing Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of" procuring sufficient energy to meet demand and reserves to meet the Synchronized Reserve, Primary Reserve, 30-minute Reserve and Regulation Requirements.²²² PJM proposes the same for clearing the Non-Synchronized Reserve markets,²²³ and the Secondary Reserve markets.²²⁴ PJM will continue to apply the joint optimization approach in which it clears the energy and reserve markets.²²⁵

PJM's proposal in this regard is a clarification, rather than a change, to PJM's current approach used to clear the markets. The current rules solely discuss opportunity cost, expressed as the product of the MW withheld from the energy market in order to provide reserves and the

²²¹ Specifically, such resources with a 30-minute lead time would be able to submit offers up to \$2,999/MWh, and those with a 60-minute lead would be able to submit offers up to \$2,000/MWh.

²²² See proposed Operating Agreement, Schedule 1, section 1.11.4C(b).

²²³ See proposed Operating Agreement, Schedule 1, section 1.11.4B(b).

²²⁴ See proposed Operating Agreement, Schedule 1, section 1.11.4C(b).

²²⁵ In this regard, PJM is proposing a couple clarifying revisions. One, PJM is updating section 2.6 to clarify that joint optimization is used in the Day-Ahead Energy Market, and two, PJM is deleting section 1.7.19A(d) which discusses procuring Synchronized Reserve using PJM's prior practice of clearing energy separately from reserves prior to the implementation of joint optimization of energy and reserves in October 2012 (original shortage pricing implementation). See proposed Operating Agreement, Schedule 1, sections 2.6(b) and 1.7.19A.

difference between the LMP and the resource's energy offer price. However, this is an overly simplistic representation of PJM's approach, which evaluates the tradeoff between assigning a resource to provide energy versus reserves when determining whether a resource should be committed to provide reserves or not.²²⁶ To clarify and make explicit PJM's approach, PJM is proposing to update the market clearing rules to instead refer to evaluation of the product substitution cost of committing a resource for reserves versus energy. The product substitution cost associated with procuring each resource takes into account all the costs associated with committing a resource, including costs, like the startup cost of an offline resource, which are not included in the current simplistic opportunity cost description. While the tariff will refer to "product substitution cost," opportunity costs are still part of the evaluation; they just are not the sole aspect being evaluated. Further, even for those resources for which PJM declares the opportunity costs are zero for pricing and settlement purposes, such as demand response resources, offline resources and synchronous condensers, the product substitution cost will take into account any energy market revenue the resource would forgo if selected to provide reserves versus energy in determining the product substitution cost of that resource. As such, the opportunity cost is not zero for these resources from a commitment perspective.²²⁷

In addition, PJM proposes to maintain limits on the amount of demand response resources that can be counted towards the Minimum Synchronized Reserve Requirement²²⁸ and

²²⁶ See, e.g., Operating Agreement, Schedule 1, section 1.11.4A(b).

²²⁷ PJM also proposes to state in its market clearing rules that when PJM assigns day-ahead reserve commitments to synchronous condensers and demand response resources with longer notification times than traditional reserve resources – which make the resources inflexible in the real-time reserve markets and requires that such resources be cleared for reserves in the hour-ahead clearing rather than every five minutes in real-time, such resources will be committed in real-time reserve markets consistent with their day-ahead reserve assignments, unless PJM dispatches the resource to provide energy or another reserve product. See proposed Operating Agreement, Schedule 1, sections 1.11.4A(b), 1.11.4B(b), and 1.11.4C(b).

²²⁸ While the current demand response limit for Synchronized Reserve is not stated in the tariff, it is stated in PJM Manual 11, Section 4.2.8, and PJM proposes to include it in the tariff as part of this proposal.

the Minimum 30-minute Reserve Requirement that can be satisfied by demand response resources.²²⁹ The current caps were adopted to ensure demand response was as effective as other resources to manage the grid based on short-term issues. The PJM Operating Committee reviews and considers further increase to these limits as demand response participation levels approach the limit has increased the participation limit to 33 percent based upon a performance review.²³⁰ However, PJM now proposes to raise these limits to 50 percent of the minimum requirements.²³¹

In other words, PJM will clear resources to provide Secondary Reserve using joint co-optimization to obtain the least-cost result, while meeting the applicable 30-minute Reserve Requirements and limiting the system's exposure to over-reliance on demand response resources.

9. *Reserve market clearing prices should reflect the inter-relation of reserve products.*

A primary goal in designing reserve markets is to ensure that resources are indifferent to providing energy or reserves. Thus, prices for reserves should account for the above-cost revenues (i.e., profit) resources would earn had the resource been dispatched for energy instead of reserves. In other words, resources should be compensated for their opportunity costs when being committed to provide reserves. This ensures that when the market operator dispatches a resource down from its current energy assignment to provide Synchronized Reserve, the resource will follow dispatch and provide the reserves needed. Current market rules apply this approach. Clearing prices for Synchronized Reserve and Non-Synchronized Reserve are determined based

²²⁹ See Operating Agreement, Schedule 1, section 3.2.3A.01(a) ("Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement.").

²³⁰ The PJM Operating Committee previously increased the participation limit in the Synchronized Reserve market from 25% to 33%. In 2018, the maximum hourly demand response resource Synchronized Reserve assignment was 25.6 percent, while the hourly average participation has ranged from approximately 5 to 13 percent.

²³¹ See proposed Operating Agreement, Schedule 1, sections 1.11.4A(b) and 1.11.4C(b).

on the cost of “serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs.”²³²

Further, the current market rules specify how PJM estimates opportunity cost for each resource providing reserves for the purposes of determining the Synchronized Reserve Market Clearing Price and Non-Synchronized Reserve Market Clearing Price.²³³ However, upon review of the current market rules, PJM determined that the opportunity cost determination used to calculate the reserve markets clearing prices, as currently described in the tariff, is incorrect, as the tariff describes it as a dollar value instead of a dollar per megawatt hour value, as required for clearing prices. The market rules in the tariff therefore need to be revised. To be clear, PJM does not believe that there is any issue with the way PJM currently calculates opportunity costs, nor any error in how prices are formed in the market today. Rather, the tariff needs to be corrected, and PJM is taking the opportunity in this filing to do so.

Accordingly, PJM is proposing several revisions to the rules describing the opportunity costs used for determining clearing prices. PJM is adding opportunity cost provisions to help determine Secondary Reserve Market Clearing Prices, both day-ahead and real-time,²³⁴ and provisions to help determine clearing prices for the Day-ahead Synchronized Reserve Market.²³⁵ PJM proposes to remove the formulaic description of the tariff’s opportunity cost description, as

²³² Operating Agreement, Schedule 1, section 3.2.3A(d).

²³³ Operating Agreement, Schedule 1, sections 3.2.3A(e), 3.2.3A.001(d).

²³⁴ See proposed Operating Agreement, Schedule 1, section 3.2.3A.01(f). In this regard, PJM is also proposing that, in the event of a Voltage Reduction Action or a Manual Load Dump Action, Secondary Reserve Market Clearing Prices should be “the sum of the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirements for each Reserve Zone or Reserve Sub-zone to which it can contribute.” *Id.* section 3.2.3A.01(d)(ii). This proposed rule mirrors the current and proposed rules for Synchronized Reserve. See Operating Agreement, Schedule 1, section 3.2.3A(d) and proposed Operating Agreement, Schedule 1, section 3.2.3A(d)(ii).

²³⁵ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(e)(i), 3.2.3A(e)(ii).

it is incorrect.²³⁶ In the formula, “A” and “B” apply only to synchronous condensers, but the formula appears to apply these factors for all resources. So, PJM is proposing to delete these and simply state the rule applicable to synchronous condensers.²³⁷ PJM is also clarifying the rules to remove the part of the formula unnecessary to solve for a dollar per megawatt hour value, i.e., factor “C”.²³⁸ In so doing, PJM proposes to retain the part of the formula that determines opportunity cost based generally on the difference between the applicable LMP and the resource’s energy offer price.²³⁹

Because there are no opportunity costs for Non-Synchronized Reserve,²⁴⁰ PJM is proposing to set the opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves at zero.²⁴¹ PJM also proposes to set opportunity costs to zero for determining both day-ahead and real-time clearing prices for synchronous condensers and resources self-scheduled to provide Synchronized Reserve.²⁴² Opportunity costs for demand response resources in the day-ahead Synchronized Reserve and Secondary Reserve markets will be determined only if the resource receives a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide reserves.²⁴³ Opportunity costs for demand response resources will be set at zero for the real-time Synchronized Reserve and Secondary Reserve markets.²⁴⁴ Finally, PJM is

²³⁶ Operating Agreement, Schedule 1, section 3.2.3A(e).

²³⁷ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(e)(i) and (ii), 3.2.3A.01(f)(i) and (ii).

²³⁸ *Id.*

²³⁹ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(e)(i) and (ii), 3.2.3A.01(f)(i) and (ii).

²⁴⁰ See *supra* section III.C.4.

²⁴¹ See proposed Operating Agreement, Schedule 1, section 3.2.3A.001(d)(i).

²⁴² See proposed Operating Agreement, Schedule 1, sections 3.2.3A(e)(i), 3.2.3A(e)(ii).

²⁴³ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(e)(i), 3.2.3A.01(f)(i).

proposing specific rules to determine opportunity costs for hydroelectric resources assigned to provide Synchronized Reserve and Secondary Reserve in real-time based on the resource's then-current operating conditions.²⁴⁵

Another basic tenet of reserve pricing is that the clearing prices are additive for products that can substitute for each other. Because a megawatt of Synchronized Reserve can go toward meeting the Synchronized Reserve Requirement and the Primary Reserve Requirement, the Synchronized Reserve Market Clearing Price reflects the cost of meeting both these requirements. For this reason, the Synchronized Reserve Market Clearing Price will always be greater than or equal to the Non-Synchronized Reserve Market Clearing Price, which represents the price of meeting the balance of the Primary Reserve Requirement in excess of the Synchronized Reserve Requirement.²⁴⁶ Further, when the system becomes short on reserves, the Synchronized Reserve Market Clearing Price includes the Reserve Penalty Factor for each reserve requirement and each Reserve Zone or Sub-zone to which a megawatt of Synchronized

²⁴⁴ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(e)(ii), 3.2.3A.01(f)(ii). Currently, the market rules set the opportunity cost of demand response resources to zero. Thus, PJM's proposal to allow a non-zero opportunity cost for demand response resource in the day-ahead market is a change. However, while in day-ahead PJM simultaneously determines both the commitment and dispatch of demand response resources for both energy and reserves (thereby establishing the basis for an opportunity cost), in real-time PJM performs the commitment and dispatch of Demand Resources in multiple stages, as follows. Because most demand response resources are inflexible (i.e., longer notification times than five minute real-time commitments allow for), they are committed for reserves an hour before the applicable performance interval in the Ancillary Services Optimizer. Each resource's product substitution cost of providing reserves as opposed to energy is considered in this commitment decision. However, real-time energy commitments for Demand Resources are deferred until IT SCED, which is about 30-minutes ahead. Any additional demand reduction capability is evaluated for an energy commitment at this time. Energy commitments resulting from IT SCED are fixed, meaning RT SCED does not revisit the decision to dispatch the resource. Thus, in real-time, when PJM dispatches the system for reserves and energy and determines the real-time prices, they are not dispatchable for energy, as their commitment/dispatch from IT SCED is fixed. This is true even for Demand Resources that do have the flexibility to accept five-minute real-time reserve commitments. Therefore, demand response resources have no opportunity cost in real-time.

²⁴⁵ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(e)(ii), 3.2.3A.01(f)(ii). The proposed rules for determining opportunity costs for hydroelectric resources mirror the rules for determining opportunity costs for hydroelectric resources in the Regulation market. See Operating Agreement, Schedule 1, section 3.2.2(d). Indeed, PJM currently uses these rules for determining opportunity costs for Synchronized Reserve.

²⁴⁶ See Operating Agreement, Schedule 1, sections 3.2.3A(d), 3.2.3A.001(c).

Reserve can contribute, leading to additive prices.²⁴⁷ Currently, the Synchronized Reserve Market Clearing Price is capped at only two Reserve Penalty Factors, despite the fact that if both the Synchronized Reserve and Primary Reserve Requirements could not be met for either the RTO Reserve Zone or the MAD Sub-zone, the Synchronized Reserve Market Clearing Price for the MAD Sub-zone should reflect all four Reserve Penalty Factors in recognition that a megawatt of Synchronized Reserve in the MAD Sub-zone can satisfy all four reserve requirements. PJM proposes to maintain this structure for Synchronized Reserve and Non-Synchronized Reserve, and add it for Secondary Reserve, as such structure recognizes that some reserve products can meet multiple reserve requirements, provide greater value to the system, and should be compensated more.

PJM's proposal does just that. PJM proposes to calculate both day-ahead and real-time reserve market clearing prices as the incremental cost of serving the next increment of demand for such reserve in a Reserve Zone or Reserve Sub-zone. Such clearing prices will be determined based on the interaction of the applicable ORDC, offer prices, and opportunity costs, as applicable, plus the incremental prices of serving the next increment of demand for such reserve product in each other Reserve Zone or Reserve Sub-zone and each other reserve requirement to which that resource can contribute.²⁴⁸

²⁴⁷ Operating Agreement, Schedule 1 section 3.2.3A(d) ("When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone.").

²⁴⁸ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(d)(i), 3.2.3A(d)(ii), 3.2.3A.001(c)(i), 3.2.3A.001(c)(ii), 3.2.3A.01(d)(i), 3.2.3A.01(d)(ii). For example, the Day-ahead and Real-time Synchronized Reserve Market Clearing Prices shall be calculated as:

the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for

Commission staff has recognized the rational for pricing with this method. In an October 2014 report in Docket No. AD14-14, Commission stated: “[t]ypically, price formation during shortages is more involved than applying a penalty factor for failing to meet a single reliability-based operating reserve requirement, and penalty factors may be additive in order to reflect the degree of the shortage or the particular operating reserve requirement not being met.”²⁴⁹

To arrive at the clearing prices, PJM must account for differing Reserve Penalty Factors, differing minimum reserve requirements, and differing ability of each product to satisfy different requirements. This necessarily results in some complexity in calculating reserve market clearing prices. Such calculations require determining interim prices, commonly referred to as shadow prices, that are not themselves clearing prices, but that are necessary steps on the path to determining clearing prices. Dr. Rocha Garrido presents in his affidavit the series of formulae PJM proposes to use to perform the clearing price calculations.²⁵⁰

10. *As energy and reserves are procured simultaneously through a joint co-optimization algorithm, PJM proposes to allow the ORDCs to interact with the energy market prices.*

Updates to the energy market pricing rules are required to implement this proposal. The current market rules allow Real-time Energy Market LMPs to increase when PJM is unable to procure sufficient reserves to meet the Synchronized Reserve Requirement and the Primary Reserve Requirement—i.e., when there is a shortage. Thus, corresponding to PJM’s proposal to procure sufficient reserves on a day-ahead basis to meet the Synchronized Reserve Requirement,

any other Reserve Zone or Reserve Sub-Zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-Zone to which the next increment of demand for Synchronized Reserve can contribute.

Proposed section 3.2.3A(d)(i) and (ii).

²⁴⁹ 2014 FERC Staff Shortage Pricing Report at 7.

²⁵⁰ Rocha Garrido Aff. ¶ 23.

the Primary Reserve Requirement, and the 30-minute Requirement, PJM is updating the rules to allow Day-ahead Energy Market LMPs to increase when PJM is unable to procure sufficient reserves to meet the minimum reserve requirements.²⁵¹

PJM is also proposing to update the provisions calculating Real-time and Day-ahead Energy Market prices to clarify that energy market prices will be determined in conjunction with clearing the reserve markets. To an extent this is already occurring in the real-time markets through PJM's joint co-optimization clearing approach, which simultaneously clears reserves and energy markets from the same pool of resources. The clearing algorithm determines the least-cost solution, which minimizes production cost, for clearing all markets. The only new element introduced in this proposal is that the sloped ORDCs for clearing the reserve markets will interact with the energy market prices even when the minimum reserve requirements are being met.

Further, PJM is proposing to update the rules to explicitly state that PJM determines prices in the Day-ahead Energy Market using “a joint optimization of energy and reserves, given scheduled system conditions, a set of energy offers, a set of reserve offers, a set of Operating Reserve Demand Curves, and any binding transmission constraints that may exist.”²⁵² PJM is also proposing to include the following clarification of how energy market prices will be determined.

Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account

²⁵¹ See proposed Operating Agreement, Schedule 1, section 2.2(d)(i). PJM is also proposing to update when shortage pricing occurs to when the “Minimum” reserve requirements are not met. This change corresponds to PJM defining the reserve requirements as any point on the applicable ORDC, while the minimum requirements represent the megawatts required to be maintained by applicable reliability standards, consistent with the current reserve requirements. See *id.*, sections 2.2(d)(ii) and 2.5(d). PJM proposes to retain the shortage pricing rules in section 2.2(d) and 2.5(d) to manage PJM's reporting requirements for when shortage pricing is triggered.

²⁵² See Operating Agreement, Schedule 1, proposed section 2.6(a).

resource constraints, transmission constraints, marginal loss impact, and the applicable Operating Reserve Demand Curves. When the marginal energy MW is provided by converting a MW of reserves into a MW of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange.²⁵³

This proposed text more explicitly spells out PJMs current approach, and expands it to include the ORDCs in the 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. This provision replaces the last sentence in both sections 2.5(a) and 2.6(a), which summarized how LMPs would be determined.

Because the ORDCs will continuously interact with energy market pricing, PJM proposes to delete the provision in the real-time LMP calculation specifically allowing Reserve Penalty Factors to be included in the LMP (but capped at two times the Reserve Penalty Factor).²⁵⁴ This provision is unnecessary as the continual interaction of the ORDCs with energy market pricing will trigger such change in energy market pricing when any minimum reserve requirement is not met.

In addition, PJM is proposing to cap the price at which Emergency energy offers can set LMP at \$2,000/MWh. Currently, resources outside of PJM, and the emergency segments of generation resources within PJM, can set LMP during Emergency actions at offers up to “the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement,”²⁵⁵ which is \$5,000/MWh with the proposed \$2,000/MWh Reserve Penalty Factors. PJM will still accept offers for Emergency energy above \$2,000/MWh under the proposed revision. Such offers will simply be capped at

²⁵³ See proposed Operating Agreement, Schedule 1, sections 2.5(b), 2.6(b).

²⁵⁴ See proposed Operating Agreement, Schedule 1, section 2.2(b).

²⁵⁵ Operating Agreement, Schedule 1, section 3.2.6(a).

\$2,000/MWh for the purpose of setting LMP, and will bring this provision in line with the proposed \$2,000/MWh Reserve Penalty Factors, and the \$2,000/MWh cost-based energy offer cap for setting LMP.²⁵⁶

11. *PJM proposes to clarify the rules for resources to self-schedule to provide reserves.*

Sellers may self-schedule resources to supply Synchronized Reserve. However, sellers that self-schedule a resource to provide Synchronized Reserve in the day-ahead market and do not deliver that megawatt quantity of Synchronized Reserve in real-time shall “buy out” of the shortfall from the real-time market at the Real-time Synchronized Reserve Market Clearing Price.²⁵⁷ This rule mirrors the one for resources self-scheduled to provide energy but fall short of their promise,²⁵⁸ and imposes the same performance obligation on self-scheduled resources as for those committed and dispatched by the clearing algorithm.²⁵⁹

Unlike for Synchronized Reserve, resources cannot self-schedule to provide Non-Synchronized Reserve or Secondary Reserve. Sellers cannot self-schedule their resources to provide Non-Synchronized Reserve because doing so would require the sellers put the resources offline which would prevent such resources from being available to provide energy. Essentially, self-scheduling to supply Non-Synchronized Reserve would allow the seller to withhold the resource from the market.

Sellers cannot self-schedule their resources to provide Secondary Reserve because this would essentially allow a seller to withhold the resource’s energy capability (10 to 30 minutes in the future) from the market. Such energy market withholding has the potential to artificially

²⁵⁶ See Operating Agreement, Schedule 1, section 2.2.

²⁵⁷ Proposed Operating Agreement, Schedule 1, section 1.10.3(e).

²⁵⁸ See Operating Agreement, Schedule 1, section 1.10.3(d).

²⁵⁹ See Operating Agreement, Schedule 1, section 1.10.1(c).

increase energy market prices, potentially for the benefit of the seller's other resources. Moreover, there likely is a lack of economic incentive to self-schedule in the Secondary Reserve market to cover a Market Seller's obligation to provide Secondary Reserves for the load it serves. All of PJM's simulations show very low prices for Secondary Reserve (\$0.00/MWh once rounded to the nearest penny).²⁶⁰ Therefore, any benefit gained from self-scheduling for Secondary Reserve would very likely be outweighed by the harm a potential gaming scheme would cause.²⁶¹

PJM is also proposing a clarifying and clean-up edit to the self-schedule rules in section 1.10.3. Currently, the rules provide that "[h]ydropower units, excluding pumped storage units, may only be self-scheduled."²⁶² However, the words "[f]or energy" have been inadvertently omitted from the beginning of this sentence, and PJM proposes to include them in this filing.²⁶³ While hydroelectric units are not part of the generation pool from which the PJM markets procure energy, they are a pool resource for reserves and regulation.

12. *With the markets in alignment, reserve settlements should mirror that currently used for energy.*

Aligning the day-ahead and real-time markets to both clear all three reserve products necessitates revisions to the rules for compensating resources providing reserves and for allocating the costs of such reserves. In the parlance of settling the markets, payments to resources are called "credits" and allocated costs are called "charges." As discussed, in

²⁶⁰ Keech Aff. ¶ 42, Table 4.

²⁶¹ While this market power concern also exists for allowing sellers to self-schedule Synchronized Reserve, the concern there is less acute. This is because the shorter, 10-minute time horizon for Synchronized Reserve reduces a Market Seller's ability to affect LMP because it involves a smaller number of megawatts. The viability of such a scheme is lessened by the nature of Synchronized Reserve, but not by the 30-minute time horizon of Secondary Reserve. Further, there is a more legitimate financial incentive to self-schedule to fulfill a Market Seller's obligation to provide Synchronized Reserves for the load it serves given that the simulations show an average SRMCP of \$7.89/MWh. See Keech Aff. ¶ 42, Table 4.

²⁶² Operating Agreement, Schedule 1 section 1.10.3(e).

²⁶³ See proposed Operating Agreement, Schedule 1, section 1.10.3(f).

developing the rules for Secondary Reserve, PJM generally mirrored the current and revised rules for Synchronized Reserve and Non-Synchronized Reserve. Thus, the general structure of the revised settlements is followed for all three reserve products. In short, that structure is as follows: resources receive credits for day-ahead assignments, real-time assignments, and for lost opportunity costs associated with providing the reserve product assigned instead of energy or a different reserve product. Load is allocated costs for procuring reserves based on whether the benefit is location-based or region-wide.

- a. Reserve market costs should continue to be allocated to the load in each Reserve Zone or Reserve Sub-zone.

Under current market rules, all Load Serving Entities have a Synchronized Reserve Obligation and a Non-Synchronized Reserve Obligation for each hour based on its total real-time load in each Reserve Zone or Reserve Sub-zone.²⁶⁴ Entities with such an obligation are charged for procuring reserves in the Reserve Zone or Reserve Sub-zone in which the entity's real-time load is located based on the real-time clearing price for such reserves multiplied by the amount of reserves procured. Load Serving Entities are also allocated a share of resources' opportunity costs of providing reserves, based on their Synchronized Reserve Obligation or Non-Synchronized Reserve Obligation, where the Synchronized Reserve Obligation is further offset by any self-scheduled Synchronized Reserve MW.²⁶⁵

PJM proposes to extend these practices to Secondary Reserve, and establish a Secondary Reserve Obligation based on each Load Serving Entity's total load in each Reserve Zone or

²⁶⁴ Operating Agreement, Schedule 1, sections 3.2.3A(a), 3.2.3A.001(a). Subject to certain requirements, Load Serving Entities may enter into agreements to share reserves with external entities, and their reserve obligations may be reduced pursuant to such agreements. *Id.*

²⁶⁵ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(h), 3.2.3A.001(f), 3.2.3A.01(h).

Reserve Sub-zone.²⁶⁶ Further, PJM proposes that a Load Serving Entity's obligation (for each product) can be adjusted through bilateral agreements and that, for each reserve product, Load Serving Entities with a reserve obligation "shall be charged the pro rata share of the sum of day-ahead and real-time credits" for that reserve product.²⁶⁷ PJM is also proposing clarifying revisions to the provisions allocating lost opportunity cost to load.

These changes ensure that load in the location for which the resource was committed to provide reserves, and which receives the reserve benefits provided, are charged.

- b. Resources should be paid through Reserve Market Clearing Price credits and lost opportunity cost credits, just like energy.

Resources are currently credited in two ways: for the clearing price credits for the megawatts that clear in the reserve market (i.e., clearing price times multiplied by megawatts), and for the lost opportunity cost of providing such reserves instead of other revenue opportunities. PJM proposes to keep this basic approach, but expand the current rules to account for the additional complexity inherent in clearing reserves day-ahead, just like energy, and in adding the Secondary Reserve product. Thus, the resources that provide reserves will now be eligible to receive the three different credits as described below.

One, just as in the energy market,²⁶⁸ resources will be eligible to receive credits for megawatts that clear in the day-ahead reserve markets equal to the megawatts cleared times the applicable day-ahead reserve market clearing price.²⁶⁹

Two, just as in the energy market,²⁷⁰ resources will be eligible to receive credits for any deviations in the amount of megawatts that clear in the real-time reserve markets as compared to

²⁶⁶ See proposed Operating Agreement, Schedule 1, section 3.2.3A.01(a).

²⁶⁷ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(a), 3.2.3A.001(a), 3.2.3A.01(a).

²⁶⁸ Operating Agreement, Schedule 1, sections 3.2.1(c), 5.1.3(c), 5.4.3(c).

²⁶⁹ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(b)(i), 3.2.3A.001(b)(i), 3.2.3A.01(b)(i).

a resource's day-ahead commitment to provide such reserve. The credits may result in revenues when the resource is assigned additional megawatts in real-time, or result in losses to the extent the resource is assigned less megawatts in real-time than day-ahead. Such real-time credits will equal the megawatt deviation from day-ahead times the applicable real-time reserve market clearing price.²⁷¹ PJM proposes to calculate these credits for each Real-time Settlement Interval (i.e., every five minutes). Also, to ensure that no megawatts are double counted as providing reserves and energy, PJM proposes to cap the amount of reserves a resource can be credited for in a given Real-time Settlement Interval at the difference between the resource's maximum available reserve capability²⁷² and the resource's energy production²⁷³ for that interval.²⁷⁴

Three, just as in the energy market,²⁷⁵ resources will be eligible to receive credits for any lost opportunity costs in both the day-ahead and real-time reserve markets associated with being assigned to provide reserves but only to the extent such opportunity costs exceed the credits received based on the market clearing prices.²⁷⁶ The calculation of how much lost opportunity cost credit a resource is eligible to receive evaluates the difference between the amount resource is credited through the market clearing prices and the energy market revenues the resource did

²⁷⁰ Operating Agreement, Schedule 1, sections 3.2.1(e), 5.1.3(f), 5.4.3(f).

²⁷¹ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(b)(ii), 3.2.3A.001(b)(ii), 3.2.3A.01(b)(ii).

²⁷² This is represented by the lesser of the resource's Economic Maximum or Synchronized Reserve maximum MW or Secondary Reserve maximum MW.

²⁷³ In settlement parlance, energy production is called "Revenue Data for Settlements." See Operating Agreement, Schedule 1, section 3.1A.

²⁷⁴ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(b)(ii), 3.2.3A.01(b)(ii) ("A=For each Real-time Settlement Interval, ... The megawatt value is capped at the Lesser of the Economic Maximum and the Synchronized Reserve Maximum MW"). Demand response resources are also eligible to receive a credit for any fixed costs associated with achieving a load reduction (e.g., shutdown costs) in the event they are dispatched in response to a Synchronized Reserve Event. *Id.* sections 3.2.3A(b)(ii), 3.2.3A.01(b)(ii).

²⁷⁵ See proposed Operating Agreement, Schedule 1, sections 3.2.3(f) through (f-4).

²⁷⁶ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(b)(iii), 3.2.3A.001(b)(iii), 3.2.3A.01(b)(iii).

not earn by following PJM’s reserve assignments. The various opportunity costs and the final determination are explained below.

i. Day-ahead and real-time opportunity costs

Because resources face different opportunity costs when they are assigned in the day-ahead and real-time markets, PJM is proposing separate, but similar, calculations for a resource’s opportunity cost in each market. In both cases, the calculation determines the profit (revenue above cost) foregone by the resource had the resource provided energy instead of reserve, based on the “deviation of the resource’s output necessary to supply a [reserve] assignment from the resource’s expected output level if it had been assigned in economic merit order to provide energy.”²⁷⁷

ii. Market Revenue Neutrality Offset

In addition, changes between a resource’s day-ahead energy and reserve assignments and its real-time energy and reserve assignments when directed by PJM create an opportunity for resources to earn additional profits (i.e., revenue above cost) that can offset losses incurred, because the resource must “buy out” of its day-ahead assignments that do not clear in real-time at the applicable real-time clearing price.²⁷⁸ To ensure that the profits “realized from the increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets”²⁷⁹ offset any losses from a resource buying out of its day-ahead assignments,

²⁷⁷ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(f)(i), 3.2.3A(f)(ii), 3.2.3A.01(f)(i), 3.2.3A.01(f)(ii). As discussed, there is no opportunity cost associated with providing Non-Synchronized Reserve because the resource is offline and incapable of providing energy in the same interval it is assigned to provide Non-Synchronized Reserve.

²⁷⁸ Currently, energy market rules require resources with a day-ahead assignment that deviate from such assignment in real-time to “buy out” of any MWs of energy they fail to provide in real-time or are not assigned to provide in real-time. See section 1.10.1(c). Consistent with procuring reserves in day-ahead and real-time, PJM is proposing to extend this “buy out” practice to assignments for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve. See proposed Operating Agreement, Schedule 1, section 1.10.1(c).

²⁷⁹ Proposed Operating Agreement, Schedule 1, Definitions M-N.

PJM is proposing to calculate a Market Revenue Neutrality Offset.²⁸⁰ The Market Revenue Neutrality Offset represents the revenue above cost the resource earns across the energy and reserve markets as a result of the change in its assignments between day-ahead and real-time.

For each Real-time Settlement Interval, PJM will determine a Market Revenue Neutrality Offset for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve and add them together. From that sum, PJM will determine the Market Revenue Neutrality Offset to be used in determining the resource's lost opportunity cost credit for each market. Thus, to determine a resource's Synchronized Reserve Market Revenue Neutrality Offset, for example, PJM would allocate the sum of these Market Revenue Neutrality Offsets to the Synchronized Reserve market "based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market."²⁸¹

In other words, the Market Revenue Neutrality Offset represents the profit earned in other reserve and energy markets that offsets any losses incurred due to a shift in the megawatts assigned in real-time relative to its day-ahead assignment for each product. Because such offsets are not accounted for in a resource's day-ahead or real-time opportunity cost calculation,²⁸² a resource's lost opportunity cost credit should account for any increase or decrease in revenues

²⁸⁰ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(f)(iii), 3.2.3A.001(d)(ii), 3.2.3A.01(f)(iii).

²⁸¹ See proposed Operating Agreement, Schedule 1, section 3.2.3A(f)(iii). PJM proposes to apply the same ratio calculation for determine the Market Revenue Neutrality Offsets for the Non-Synchronized Reserve market and the Secondary Reserve market, but use the resource's assignment and opportunity costs for such markets in the calculation. See proposed Operating Agreement, Schedule 1, sections 3.2.3A.001(d)(ii), 3.2.3A.01(f)(iii).

²⁸² See, e.g., proposed Operating Agreement, Schedule 1, sections 3.2.3A(f)(i), 3.2.3A(f)(ii) (Synchronized Reserve real-time and day-ahead opportunity cost calculations).

resulting from such shift.²⁸³ Otherwise, a resource may not be economically indifferent to the product it provides in real-time.

However, to be eligible to recover any Market Revenue Neutrality Offset in its lost opportunity cost credit, a resource must not act in a manner that results in the resource's real-time reserve assignment being less than its day-ahead assignment. For each reserve product, PJM is proposing to list the various actions that can result in the resource losing its eligibility to recover a Market Revenue Neutrality Offset for that reserve product.²⁸⁴ When ineligible for the Market Revenue Neutrality Offset, the lost opportunity cost determination will include "the opportunity cost credit owed due to a reduction in assignment in real-time,"²⁸⁵ such that the resource will not receive any opportunity cost credits for the opportunity cost the resource's own actions created.²⁸⁶

iii. Determination of lost opportunity costs credits

Based on these inputs, plus offer prices for Synchronized Reserves, PJM proposes to determine a resource's lost opportunity cost credit as the resource's costs (as reflected in both opportunity costs and, for Synchronized Reserve, offer prices) minus reserve market revenues minus the Market Revenue Neutrality Offset allocated to that reserve product.²⁸⁷ If the value is positive, then the resource is not earning enough revenue in the markets to cover its other

²⁸³ For example, if, for given 5-minute interval, a resource has day-ahead assignments of 10 MWs of energy, 5 MWs of Synchronized Reserve, and 5 MWs of Secondary Reserve, and in real-time PJM dispatches the resource to provide in that interval, 15 MWs of energy, 5 MWs of Synchronized Reserve, and 0 MWs of Secondary Reserve, then PJM would calculate a Market Revenue Neutrality Offset to ensure that the revenues associated with the real-time shift of 5 MWs from Secondary Reserve to energy is accounted for in the resource's lost opportunity cost credit.

²⁸⁴ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(f)(iii), 3.2.3A.001(d)(ii), 3.2.3A.01(f)(iii).

²⁸⁵ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(f)(iv), 3.2.3A.001(d)(iii), 3.2.3A.01(f)(iv).

²⁸⁶ For example, if a resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled in another market, then the resource is not eligible to recover any opportunity cost credits due to such deviation in Synchronized Reserve assignments. See proposed Operating Agreement, Schedule 1, section 3.2.3A(f)(iii).

²⁸⁷ See proposed Operating Agreement, Schedule 1, sections 3.2.3A(f)(iv), 3.2.3A.001(d)(iii), 3.2.3A.01(f)(iv).

revenue opportunities, and it is eligible for a lost opportunity cost credit in that amount. Such a credit is designed to ensure the resource follows PJM dispatch and is indifferent as to providing reserves or energy. If the value is negative, then the resource's reserve market revenues exceed the revenues it would have earned in the energy market, and PJM proposes to account for such excess revenues in calculating the resource's balancing Operating Reserves credits.²⁸⁸

For example, for each Real-time Settlement Interval, the Synchronized Reserve lost opportunity cost credit is determined as follows. First, add up the resource's costs, which are reflected in its cost-based offer price times its Synchronized Reserve megawatt assignment for both the day-ahead and real-time markets,²⁸⁹ and its day-ahead and real-time opportunity costs.²⁹⁰ Second, add up the resource's revenues, i.e., its day-ahead market and its real-time market clearing price credits, and add the ratio share of the Market Revenue Neutrality Offset allocated to Synchronized Reserve.²⁹¹ If the costs are greater than the revenues, then the resource is eligible for Synchronized Reserve lost opportunity cost credit.

The lost opportunity cost credit calculation is slightly different for Secondary Reserve. There, because there are no offer prices allowed, the calculation simply includes only opportunity costs on the cost side.

For Non-Synchronized Reserve, the cost side of the equation is zero. That is, as discussed above, because offline resources have no opportunity costs associated with being

²⁸⁸ See proposed Operating Agreement, Schedule 1, section 3.2.3(e).

²⁸⁹ See proposed Operating Agreement, Schedule 1, section 3.2.3A(f)(iv) at formula inputs A (day-ahead) and B (real-time). Consistent with PJM's proposed approach for determining real-time reserve market credits, the MWs of reserve assigned in real-time is capped at the resource's maximum available reserve capability less its energy production.

²⁹⁰ See proposed Operating Agreement, Schedule 1, section 3.2.3A(f)(iv) at formula inputs C (day-ahead) and D (real-time).

²⁹¹ See proposed Operating Agreement, Schedule 1, section 3.2.3A(f)(iv) at formula inputs E (day-ahead) and F (real-time).

offline. However, resources may nonetheless be eligible for a Non-Synchronized Reserve lost opportunity cost credit. Because the formula is cost minus revenues minus the Market Revenue Neutrality Offset, the calculation can only result in a positive number if a resource's real-time clearing price credits are negative due to a decrease in its real-time assignment relative to its day-ahead assignment and such credits are large enough that the calculations yields a positive value. Stated another way, to receive a Non-Synchronized Reserve lost opportunity cost credit, the resource must have had to buy out of its day-ahead Non-synchronized Reserve assignment at a cost that exceeded its day-ahead clearing price credits, which would mean that the Real-time Non-Synchronized Reserve Market Clearing Price was higher than the day-ahead clearing price.

D. PJM's Simulations of its Proposal Show Intuitive Effects on Energy and Market Reserve Price Formation.

As Mr. Keech explains in detail, PJM performed three simulations to measure the effects of: (1) Case A – removing Tier 1 Synchronized Reserve and treating all Synchronized Reserve as Tier 2;²⁹² (2) Case B – same as Case A, but also re-solving the presumed day-ahead unit commitment with the benefit of actual real-time operational data, but not adding in any other aspect of PJM's proposal;²⁹³ and (3) Case C – adjusting for all of PJM's proposal (i.e., Tier 1 removal, new ORDCs, and day-ahead and real-time reserve market alignment) and re-solving the presumed day-ahead unit commitment with the benefit of actual real-time operational data.²⁹⁴

Mr. Keech explains that adjusting the unit commitment, in Cases B and C, “remove[s] uncertainty from the unit commitment process”²⁹⁵ and “is more optimal than Case A,” because “there is less uneconomic supply running at costs above the LMP, higher market prices due to

²⁹² Keech Aff. ¶¶ 28-37.

²⁹³ *Id.* ¶¶ 38-41.

²⁹⁴ *Id.* ¶¶ 39-46.

²⁹⁵ *Id.* ¶ 43.

less price suppression, and significantly less uplift.”²⁹⁶ “To determine the effect of PJM’s proposed ORDCs, the relevant cases to compare are Case B and Case C,”²⁹⁷ and the “major differences between [the results from] Cases B and C are the increases in committed reserve amounts, reserve prices, and reserve revenues for suppliers.”²⁹⁸ Mr. Keech finds these results to be “intuitive given the change in the ORDC.”²⁹⁹ Based on these simulations “PJM estimates the increase in energy and reserve market billing from its proposal to be approximately \$556 million,” but “there will be offsetting savings that are not quantified here.”³⁰⁰ Mr. Keech identifies some of those benefits, “including anticipated reductions in the capacity market costs due to an increase in energy and reserve market revenues. Additionally, the energy and reserve markets provide incentives for availability during all hours, flexibility, and a low incremental cost of production.”³⁰¹ Notably, by creating a base case for comparison purposes that properly accounts for the reduction in production cost that is derived by performing the full unit commitment against actual net operational data rather than from changes to the PJM proposal, the impact of PJM’s proposal drops from approximately \$1.5 billion to \$556 million.

²⁹⁶ *Id.* ¶ 40.

²⁹⁷ *Id.* ¶ 43.

²⁹⁸ Keech Aff. ¶ 44.

²⁹⁹ *Id.* ¶ 44.

³⁰⁰ *Id.* ¶ 46.

³⁰¹ *Id.* ¶ 46.

The results of the simulations are shown in Figure 11 below

Figure 11. Effect of PJM's Proposal³⁰²

Variable	Case B	Case C	Case C minus Case B	Difference
	Case A with Full Unit Commitment	PJM Proposal with Full Unit Commitment		
Load Weighted LMP (\$/MWh)	37.30	37.76	0.46	1.23%
Generator Energy Revenue (\$M)	27,946	28,312	366	1.31%
Weighted Synchronized Reserve MCP (\$/MWh)	2.58	7.89	5.31	205.81%
Weighted Non-Synchronized Reserve MCP (\$/MWh)	1.26	3.97	2.71	215.0%
Weighted Secondary Reserve MCP (\$/MWh)	N/A	0.00	N/A	N/A
Hourly Average Cleared Synchronized Reserve (MW/hour)	1,818	3,168	1,350	74.26%
Hourly Average Cleared Non-Synchronized Reserve (MW/hour)	634	678	44	6.94%
Hourly Average Cleared Secondary Reserves (MW/hour)	N/A	1,943	N/A	N/A
Hourly Average Cleared Total Reserve (MW/hour)	2,452	5,789	3,337	136.09%
Total Cleared Synchronized Reserve (millions MWh)	15.5	26.9	11.4	73.55%
Total Cleared Non-Synchronized Reserve (millions MWh)	5.4	5.8	0.4	7.41%
Total Cleared Secondary Reserve (millions MWh)	N/A	16.6	N/A	N/A
Reserve Revenue (\$M)	46.8	235.9	189.1	404.06%
Uplift (\$M) ³⁰³	30.4	26.8	-3.60	-11.84%
Bid Production Cost (\$M)	13,121	13,152	31	0.26%
Total Energy and Reserve Market Revenues (\$M)	27,993	28,548	555	1.98%

IV. EFFECTIVE DATE

PJM respectfully requests an effective date of June 1, 2020, and Commission action by December 15, 2019. In order to afford PJM sufficient time to implement the proposed revisions,

³⁰² Keech Aff. ¶ 43, Table 5.

³⁰³ Uplift values reported with the simulations results are based on resources that are scheduled to operate in the simulation but do not collect enough market revenues to cover their operating cost over the day. PJM's current market rules perform this calculation over run segments. The implementation of segment-based make whole payments is not performed in this calculation.

including the necessary software changes, PJM respectfully requests an order from the Commission by no later than December 15, 2019.

V. COMMUNICATIONS

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

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VI. DOCUMENTS ENCLOSED

This filing consists of the following:

1. This transmittal letter;
2. Revisions to the PJM Operating Agreement in redlined as Attachment A in electronic tariff filing format as required by Order No. 714;
3. Revisions to the PJM Operating Agreement in non-redlined format Attachment B in electronic tariff filing format as required by Order No. 714;
4. Affidavit of Drs. William W. Hogan and Susan L. Pope on Behalf of PJM, as Attachment C;
5. Affidavit of Adam Keech on Behalf of PJM, as Attachment D;
6. Affidavit of Christopher Pulong on Behalf of PJM, as Attachment E; and

7. Affidavit of Dr. Patricio Rocha Garrido on behalf of PJM, as Attachment F.

VII. SERVICE

PJM has served a copy of this filing on all PJM members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,³⁰⁴ PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: <http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx> with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM members and all state utility regulatory commissions in the PJM Region alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: <http://www.ferc.gov/docs-filing/elibrary.asp> in accordance with the Commission's regulations and Order No. 714.

³⁰⁴ See 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3).

VIII. CONCLUSION

Accordingly, PJM respectfully requests that the Commission find (1) PJM's Operating Agreement, Schedule 1 and Tariff, Attachment K-Appendix unjust and unreasonable as discussed in this filing and (2) PJM's proposed market rule revisions are a just and reasonable replacement rate.

Respectfully submitted,



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On behalf of
PJM Interconnection, L.L.C.

March 29, 2019

Attachment A

Revisions to the PJM Operating Agreement (Redline)

Definitions A - B

30-minute Reserve:

“30-minute Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

“30-minute Reserve Requirement” shall mean the demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, as defined by the Operating Reserve Demand Curve for 30-minute Reserve. The requirement can be satisfied by any combination of Synchronized Reserve, Non-Synchronized Reserve or Secondary Reserve resources.

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A and the parallel provisions of Tariff, Attachment K-Appendix, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 and Tariff, Attachment K-Appendix, section 1.9.4.

Act:

“Act” shall mean the Delaware Limited Liability Company Act, Title 6, §§ 18-101 to 18-1109 of the Delaware Code.

Active and Significant Business Interest:

“Active and Significant Business Interest” is a term that shall be used to assess the scope of a Member’s PJM membership and shall be based on a Member’s activity in the PJM RTO and/or Interchange Energy Markets. A Member’s Active and Significant Business Interest shall: 1) be determined relative to the scope of the Member’s PJM membership and activity in the PJM RTO and/or Interchange Energy Markets considering, among other things, the Member’s public statements and/or regulatory filings regarding its PJM activities; and 2) reflect a substantial contributor to the Member’s recent market activity, revenues, costs, investment, and/or earnings when considering the Member and its corporate affiliates’ interests within the PJM footprint.

Additional Day-ahead Scheduling Reserves Requirement:

“Additional Day-ahead Scheduling Reserves Requirement” shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

Affected Member:

“Affected Member” shall mean a Member of PJM which as a result of its participation in PJM’s markets or its membership in PJM provided confidential information to PJM, which confidential information is requested by, or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which controls the other or that are under common control. “Control” shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

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

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

Annual Meeting of the Members:

“Annual Meeting of the Members” shall mean the meeting specified in Operating Agreement, section 8.3.1.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Associate Member:

“Associate Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.7.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Commission:

“Authorized Commission” shall mean (i) a State public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

Authorized Person:

“Authorized Person” shall have the meaning set forth in Operating Agreement, section 18.17.4.

Balancing Congestion Charges:

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to

Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

~~Base Day-ahead Scheduling Reserves Requirement:~~

~~“Base Day-ahead Scheduling Reserves Requirement” shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.~~

Batch Load Economic Load Response Participant Resource~~Demand Resource~~:

“Batch Load Economic Load Response Participant Resource~~Demand Resource~~” shall mean an Economic Load Response Participant resource ~~Demand Resource~~ that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit’s capacity that is designated as a Generation Capacity Resource, or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Board Member:

“Board Member” shall mean a member of the PJM Board.

Definitions C - D

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Storage Resource:

“Capacity Storage Resource” shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM’s markets such as through a Fixed Resource Requirement Capacity Plan.

Catastrophic Force Majeure:

“Catastrophic Force Majeure” shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection’s determination is subject to review by the Commission.

Cold/Warm/Hot Notification Time:

“Cold/Warm/Hot Notification Time” shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans,

water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

“Cold Weather Alert” shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Committed Offer:

The “Committed Offer shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, or Operating Agreement, Schedule 1, section 6.6 for a particular clock hour for an Operating Day.

Compliance Monitoring and Enforcement Program:

“Compliance Monitoring and Enforcement Program” shall mean the program to be used by the NERC and the Regional Entities to monitor, assess and enforce compliance with the NERC Reliability Standards. As part of a Compliance Monitoring and Enforcement Program, NERC and the Regional Entities may, among other things, conduct investigations, determine fault and assess monetary penalties.

Congestion Price:

“Congestion Price” shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

“Consolidated Transmission Owners Agreement,” “PJM Transmission Owners Agreement” or Transmission Owners Agreement” shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

- (a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;
- (d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and
- (e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i)

any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the extent that energy serves that Member's own load.

Credit Breach:

"Credit Breach" is the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in Schedule A to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailed Service Provider:

"Curtailed Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Day-ahead Congestion Price:

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the

Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

“Day-ahead Loss Price” shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

“Day-ahead Prices” shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-Ahead Pseudo-Tie Transaction:

“Day-Ahead Pseudo-Tie Transaction” shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

~~Day-ahead Scheduling Reserves:~~

~~“Day-ahead Scheduling Reserves” shall mean thirty-minute reserves as defined by the ReliabilityFirst Corporation and SERC.~~

~~Day-ahead Scheduling Reserves Market:~~

~~“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.~~

~~Day-ahead Scheduling Reserves Requirement:~~

~~“Day-ahead Scheduling Reserves Requirement” shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.~~

~~Day-ahead Scheduling Reserves Resources:~~

~~“Day-ahead Scheduling Reserves Resources” shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.~~

Day-ahead Settlement Interval:

“Day-ahead Settlement Interval” shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

“Day-ahead System Energy Price” shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default Allocation Assessment:

“Default Allocation Assessment” shall mean the assessment determined pursuant to Operating Agreement, section 15.2.2.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

“Demand Bid Screening” shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

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

Designated Entity:

“Designated Entity” shall mean an entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Operating Agreement, Schedule 6, section 1.5.8.

Direct Charging Energy:

“Direct Charging Energy” shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Dispatch Rate:

“Dispatch Rate” shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dispatched Charging Energy:

“Dispatched Charging Energy” shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing a service in the PJM markets.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Dynamic Transfer:

“Dynamic Transfer” shall mean a Pseudo-Tie or Dynamic Schedule.

Definitions E - F

Economic-based Enhancement or Expansion:

“Economic-based Enhancement or Expansion” shall mean an enhancement or expansion described in Operating Agreement, Schedule 6, section 1.5.7(b) (i) – (iii) that is designed to relieve transmission constraints that have an economic impact.

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective Date:

“Effective Date” shall mean August 1, 1997, or such later date that FERC permits the Operating Agreement to go into effect.

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common

ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EIDSN, Inc.:

“EIDSN, Inc.” shall mean the nonstock, nonprofit corporation, formerly known as Eastern Interconnection Data Sharing Network, Inc., or any successor thereto, that is operated primarily for the purpose of developing operating tools and the facilitation of the secure, consistent, effective, and efficient sharing of important electric transmission and operational data among reliability coordinators and other relevant parties to help improve electric industry operations and promote the reliable and efficient operation of the bulk electric system in the Eastern Interconnection.

Electric Distributor:

“Electric Distributor” shall mean a Member that: 1) owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

“Emergency” shall mean: (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

Emergency Load Response Program:

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

End-Use Customer:

“End-Use Customer” shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Member Committee classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced

capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Market Opportunity Cost:

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Storage Resource:

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant.

Energy Storage Resource Model Participant:

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-XXX-000.

Equivalent Load:

“Equivalent Load” shall mean the sum of a Market Participant’s net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

~~Extended Primary Reserve Requirement:~~

~~“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.~~

Extended Synchronized Reserve Requirement:

~~“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.~~

External Market Buyer:

“External Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

“External Resource” shall mean a generation resource located outside the metered boundaries of the PJM Region.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Final Offer:

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for an Operating Day.

Finance Committee:

“Finance Committee” shall mean the body formed pursuant to Operating Agreement, section 7.5.1.

Financial Transmission Right:

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Financial Transmission Right Option:

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Flexible Resource:

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall mean individual Transmission Owner FERC-filed planning criteria as described in Operating Agreement, Schedule 6, section 1.2(e) and filed with FERC Form No. 715 and posted on the PJM website.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

Fuel Cost Policy:

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offer(s) for a generation resource.

Definitions I - L

Immediate-need Reliability Project:

“Immediate-need Reliability Project” shall mean a reliability-based transmission enhancement or expansion that the Office of the Interconnection has identified to resolve a need that must be addressed within three years or less from the year the Office of the Interconnection identified the existing or projected limitations on the Transmission System that gave rise to the need for such enhancement or expansion pursuant to the study process described in Operating Agreement, Schedule 6, section 1.5.3.

Inadvertent Interchange:

“Inadvertent Interchange” shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

Increment Offer:

“Increment Offer” shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.

Incremental Energy Offer:

“Incremental Energy Offer” shall mean offer segments comprised of a pairing of price (in dollars per MWh) and megawatt quantities, which must be a non-decreasing function and taken together produce all of the energy segments above a resource’s Economic Minimum. No-load Costs are not included in the Incremental Energy Offer.

Incremental Multi-Driver Project:

“Incremental Multi-Driver Project” shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Information Request:

“Information Request” shall mean a written request, in accordance with the terms of the Operating Agreement for disclosure of confidential information pursuant to Operating Agreement, section 18.17.4.

Interface Pricing Point:

“Interface Pricing Point” shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.6A.

Internal Market Buyer:

“Internal Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service

Interregional Transmission Project:

“Interregional Transmission Project” shall mean transmission facilities that would be located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to regional transmission needs.

LLC:

“LLC” shall mean PJM Interconnection, L.L.C., a Delaware limited liability company.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Reduction Event:

“Load Reduction Event” shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

“Load Serving Charging Energy” shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity:

“Load Serving Entity” or “LSE” shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of

transmission and ancillary services.

Local Plan:

“Local Plan” shall include Supplemental Projects as identified by the Transmission Owners within their zone and Subregional RTEP projects developed to comply with all applicable reliability criteria, including Transmission Owners’ planning criteria or based on market efficiency analysis and in consideration of Public Policy Requirements.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

Locational Marginal Price:

“Locational Marginal Price” or “LMP” shall mean the market clearing marginal price for energy at the location the energy is delivered or received, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus and adjusted for any reduction in megawatts due to Regulation, or Tier 2 Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Long-lead Project:

“Long-lead Project” shall mean a transmission enhancement or expansion with an in-service date more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect

on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Definitions M - N

M2M Flowgate:

“M2M Flowgate” shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Market Buyer:

“Market Buyer” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and that is otherwise able to make purchases in the PJM Interchange Energy Market.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” shall mean the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM.

Market Operations Center:

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

“Market Revenue Neutrality Offset” shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller:

“Market Seller” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and that is otherwise able to make sales in the PJM Interchange Energy Market.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Generation Emergency:

“Maximum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical

power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.6 and that (i) is a member of the LLC immediately prior to the Effective Date, or (ii) has executed an Additional Member Agreement in the form set forth in Operating Agreement, Schedule 4.

Members Committee:

“Members Committee” shall mean the committee specified in Operating Agreement, section 8, composed of representatives of all the Members.

Minimum 30-minute Reserve Requirement:

“Minimum 30-minute Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as 30-minute Reserve, inclusive of any increase to account for additional reserves scheduled to address operational uncertainty. The Minimum 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals

and establishes the first segment on the Operating Reserve Demand Curve for 30-minute Reserve.

Minimum Generation Emergency:

“Minimum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker opening and after the unit’s generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, “Minimum Down Time” shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Primary Reserve Requirement:

“Minimum Primary Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve, inclusive of any increase to account for additional reserves scheduled to address operational uncertainty. The Minimum Primary Reserve Requirement is calculated in accordance with the PJM Manuals, and establishes the first segment on the Operating Reserve Demand Curve for Primary Reserve.

Minimum Run Time:

For all generating units that are not combined cycle units, “Minimum Run Time” shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, “Minimum Run Time” shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM’s State Estimator.

Minimum Synchronized Reserve Requirement:

“Minimum Synchronized Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, inclusive of any increase to account for additional reserves scheduled to address operational uncertainty. The Minimum Synchronized Reserve Requirement is calculated in accordance with the PJM

Manuals, and establishes the first segment on the Operating Reserve Demand Curve for Synchronized Reserve.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Multi-Driver Project:

“Multi-Driver Project” shall mean a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation, or any successor thereto.

NERC Functional Model:

“NERC Functional Model” shall be the set of functions that must be performed to ensure the reliability of the electric bulk power system. The NERC Reliability Standards establish the requirements of the responsible entities that perform the functions defined in the Functional Model.

NERC Interchange Distribution Calculator:

“NERC Interchange Distribution Calculator” shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

NERC Reliability Standards:

“NERC Reliability Standards” shall mean those standards that have been developed by NERC and approved by FERC to ensure the reliability of the electric bulk power system.

NERC Rules of Procedure: “NERC Rules of Procedure” shall be the rules and procedures developed by NERC and approved by the FERC. These rules include the process by which a responsible entity, who is to perform a set of functions to ensure the reliability of the electric bulk power system, must register as the Registered Entity.

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads

resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Network Resource:

“Network Resource” shall have the meaning specified in the PJM Tariff.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

Non-Disclosure Agreement:

“Non-Disclosure Agreement” shall mean an agreement between an Authorized Person and the Office of the Interconnection, pursuant to Operating Agreement, section, the form of which is appended to this Agreement as Operating Agreement, Schedule 10, wherein the Authorized Person is given access to otherwise restricted confidential information, for the benefit of their respective Authorized Commission.

Non-Dispatched Charging Energy:

“Non-Dispatched Charging Energy” shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Nonincumbent Developer:

“Nonincumbent Developer” shall mean: (1) a transmission developer that does not have an existing Zone in the PJM Region as set forth in Tariff, Attachment J; or (2) a Transmission

Owner that proposes a transmission project outside of its existing Zone in the PJM Region as set forth in Tariff, Attachment J.

Non-Regulatory Opportunity Cost:

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, 1.5A.6.

Normal Maximum Generation:

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

Definitions O - P

Offer Data:

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

Office of the Interconnection:

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

Office of the Interconnection Control Center:

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

On-Site Generators:

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

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

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

Operating Day:

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

Operating Margin:

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

Operating Margin Customer:

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

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Operating Reserve Demand Curve:

“Operating Reserve Demand Curve” shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that can be used to meet a given reserve requirement and the value placed on maintaining that megawatt level of reserve, expressed in \$/MWh.

Operator-initiated Commitment:

“Operator-initiated Commitment” shall mean a commitment after the Day-ahead Energy Market and Day-ahead Scheduling Reserves Market, whether manual or automated, for a reason other than minimizing the total production costs of serving load.

Original PJM Agreement:

“Original PJM Agreement” shall mean that certain agreement between certain of the Members, originally dated September 26, 1956, and as amended and supplemented up to and including December 31, 1996, relating to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems.

Other Supplier:

“Other Supplier” shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, financial transmission rights or other services available under PJM’s governing documents in or through the Interconnection or has a good faith intent to do so, and; (ii) does not qualify for the Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer sectors.

PJM Board:

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

PJM Control Area:

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

PJM Dispute Resolution Procedures:

“PJM Dispute Resolution Procedures” shall mean the procedures for the resolution of disputes set forth in Operating Agreement, Schedule 5.

PJM Governing Agreements:

“PJM Governing Agreements” shall mean the PJM Open Access Transmission Tariff, the Operating Agreement, the Consolidated Transmission Owners Agreement, the Reliability Assurance Agreement, or any other applicable agreement approved by the FERC and intended to govern the relationship by and among PJM and any of its Members.

PJM Interchange:

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

PJM Interchange Energy Market:

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

PJM Interchange Export:

“PJM Interchange Export” shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the

amount by which its interval Equivalent Load is exceeded by the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller.

PJM Interchange Import:

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

PJM Manuals:

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

PJM Mid-Atlantic Region:

“PJM Mid-Atlantic Region” shall mean the aggregate of the Transmission Facilities of Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC, PECO Energy Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric and Gas Company, and Rockland Electric Company.

PJM Region:

“PJM Region” shall mean the aggregate of the Zones within PJM as set forth in Tariff, Attachment J.

PJMSettlement:

“PJMSettlement” or “PJM Settlement, Inc.” shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operating Agreement, section 3.3.

PJM South Region:

“PJM South Region” shall mean the Transmission Facilities of Virginia Electric and Power Company.

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

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

PJM West Region:

“PJM West Region” shall mean the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Affiliate Companies; The Dayton Power and Light Company; the Duquesne Light Company; American Transmission Systems, Incorporated; Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc. and East Kentucky Power Cooperative, Inc.

Planning Period:

“Planning Period” shall *have the meaning specified in the Reliability Assurance Agreement.*

Planning Period Balance:

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

Planning Period Quarter:

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

Point-to-Point Transmission Service:

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

PRD Curve:

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

PRD Provider:

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

PRD Reservation Price:

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

PRD Substation:

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

Pre-Emergency Load Response Program:

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

President:

“President” shall have the meaning specified in Operating Agreement, section 9.2.

Price Responsive Demand:

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

Primary Reserve:

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

Primary Reserve Alert:

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

Primary Reserve Requirement:

“Primary Reserve Requirement” shall mean the demand for Primary Reserves megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as defined by the Operating Reserve Demand Curve for Primary Reserve. The requirement can be satisfied by any combination of Synchronized Reserve or Non-Synchronized Reserve resources, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Prohibited Securities:

“Prohibited Securities” shall mean the Securities of a Member, Eligible Customer, or Nonincumbent Developer, or their Affiliates, if:

(1) the primary business purpose of the Member or Eligible Customer, or their Affiliates, is to buy, sell or schedule energy, power, capacity, ancillary services or transmission services as indicated by an industry code within the “Electric Power Generation, Transmission, and Distribution” industry group under the North American Industry Classification System (“NAICS”) or otherwise determined by the Office of the Interconnection;

(2) the Nonincumbent Developer has been pre-qualified as eligible to be a Designated Entity pursuant to Operating Agreement, Schedule 6;

(3) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during its most recently completed fiscal year is equal to or greater than 0.5% of its gross revenues for the same time period; or

(4) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during the prior calendar year is equal to or greater than 3% of the total transactions for which PJMSettlement is a Counterparty pursuant to Operating Agreement, section 3.3 for the same time period.

The Office of the Interconnection shall compile and maintain a list of the Prohibited Securities publicly traded and post this list for all employees and distribute the list to the Board Members.

Proportional Multi-Driver Project:

“Proportional Multi-Driver Project” shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Pseudo-Tie:

“Pseudo-Tie shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Public Policy Objectives:

“Public Policy Objectives” shall refer to Public Policy Requirements, as well as public policy initiatives of state or federal entities that have not been codified into law or regulation but which nonetheless may have important impacts on long term planning considerations.

Public Policy Requirements:

“Public Policy Requirements” shall refer to policies pursued by: (a) state or federal entities, where such policies are reflected in duly enacted statutes or regulations, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations; and (b) local governmental entities such as a municipal or county government, where such policies are reflected in duly enacted laws or regulations passed by the local governmental entity.

Definitions Q - R

Ramping Capability:

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

Real-time Congestion Price:

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

Real-time Loss Price:

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

Real-time Offer:

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

Real-time Prices:

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

Real-time Energy Market:

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

Real-time Settlement Interval:

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

Real-time System Energy Price:

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

Regional Entity:

“Regional Entity” shall mean an organization that NERC has delegated the authority to propose and enforce reliability standards pursuant to the Federal Power Act.

Regional RTEP Project:

“Regional RTEP Project” shall mean a transmission expansion or enhancement rated at 230 kV or above which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Registered Entity:

“Registered Entity” shall mean the entity registered under the NERC Functional Model and NERC Rules of Procedures for the purpose of compliance with NERC Reliability Standards and responsible for carrying out the tasks within a NERC function without regard to whether a task or tasks are performed by another entity pursuant to the terms of the PJM Governing Agreements.

Regulation:

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

Regulation Zone:

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

Related Parties:

“Related Parties” shall mean, solely for purposes of the governance provisions of the Operating Agreement: (i) any generation and transmission cooperative and one of its distribution cooperative members; and (ii) any joint municipal agency and one of its members. For purposes of the Operating Agreement, representatives of state or federal government agencies shall not be deemed Related Parties with respect to each other, and a public body's regulatory authority, if any, over a Member shall not be deemed to make it a Related Party with respect to that Member.

Relevant Electric Retail Regulatory Authority:

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

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

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

Reserve Penalty Factor:

“Reserve Penalty Factor” shall mean the maximum production cost, in \$/MWh, willing to be incurred to meet the Minimum Primary Reserve Requirement, Minimum Synchronized Reserve Requirement, or Minimum 30-minute Reserve Requirement associated with being unable to meet a specific reserve requirement in for a given Reserve Zone or Reserve Sub-zone, as specified by the applicable Operating Reserve Demand Curve. ~~A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.~~

Reserve Sub-zone:

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

Reserve Zone:

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

Residual Auction Revenue Rights:

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

Residual Metered Load:

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

Revenue Data for Settlements:

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

Definitions S – T

Secondary Reserve:

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

Sector Votes:

“Sector Votes” shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Operating Agreement, section 8.4.

Securities:

“Securities” shall mean negotiable or non-negotiable investment or financing instruments that can be sold and bought. Securities include bonds, stocks, debentures, notes and options.

Segment:

“Segment” shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(e).

Senior Standing Committees:

“Senior Standing Committees” shall mean the Members Committee, and the Markets, and Reliability Committee, as established in Operating Agreement, section 8.1 and Operating Agreement, section 8.6.

SERC:

“SERC” or “Southeastern Electric Reliability Council” shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

Short-term Project:

“Short-term Project” shall mean a transmission enhancement or expansion with an in-service date of more than three years but no more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Special Member:

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

Spot Market Backup:

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

Spot Market Energy:

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

Standing Committees:

“Standing Committees” shall mean the Members Committee, the committees established and maintained under Operating Agreement, section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

Start-Up Costs:

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

State:

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

State Certification:

“State Certification” shall mean the Certification of an Authorized Commission, pursuant to Operating Agreement, section 18, the form of which is appended to the Operating Agreement as Operating Agreement, Schedule 10A, wherein the Authorized Commission identifies all

Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Estimator:

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

Station Power:

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

Sub-meter:

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

Subregional RTEP Project:

“Subregional RTEP Project” shall mean a transmission expansion or enhancement rated below 230 kV which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Supplemental Project:

“Supplemental Project” shall mean a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii).

Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

Synchronized Reserve:

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

Synchronized Reserve Event:

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

Synchronized Reserve Requirement:

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

System:

“System” shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

System Energy Price:

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

Target Allocation:

“Target Allocation” shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3 or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Party Request:

“Third Party Request” shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or the Market Monitoring Unit. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

Tie Line:

“Tie Line” shall have the same meaning provided in the Open Access Transmission Tariff.

Total Lost Opportunity Cost Offer:

“Total Lost Opportunity Cost Offer” shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated costbased Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Operating Reserve Offer:

“Total Operating Reserve Offer” shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses, which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

“Transmission Congestion Credit” shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Customer:

“Transmission Customer” shall have the meaning set forth in the PJM Tariff.

Transmission Facilities:

“Transmission Facilities” shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Forced Outage:

“Transmission Forced Outage” shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the

relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Loading Relief:

“Transmission Loading Relief” shall mean NERC’s procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loading Relief Customer:

“Transmission Loading Relief Customer” shall mean an entity that, in accordance with Operating Agreement, Schedule 1, section 1.10.6A and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

Transmission Loss Charge:

“Transmission Loss Charge” shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall mean an upgrade to a Transmission Owner’s own transmission facilities, which is an improvement to, addition to, or replacement of a part of, an existing facility and is not an entirely new transmission facility.

Transmission Planned Outage:

“Transmission Planned Outage” shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix, or the PJM Manuals.

Turn Down Ratio:

“Turn Down Ratio” shall mean the ratio of a generating unit’s economic maximum megawatts to its economic minimum megawatts.

1.5A Economic Load Response Participant.

As used in this section 1.5A, the term “end-use customer” refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number.

1.5A.1 Qualification.

A Member or Special Member that is an end-use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis (or for non-interval metered residential Direct Load Control customers, as metered on a statistical sample of electric distribution company accounts utilizing current data, as described in the PJM Manuals) or has an On-Site Generator that enables demand reduction may become an Economic Load Response Participant by complying with the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with this section 1.5A including, but not limited to, section 1.5A.3 below. A Member or Special Member may aggregate multiple individual end-use customer sites to qualify as an Economic Load Response Participant, subject to the requirements of section 1.5A.10 below.

1.5A.2 Special Member.

Entities that are not Members and desire to participate solely in the Real-time Energy Market by reducing demand may become a Special Member by paying an annual membership fee of \$500 plus 10% of each payment owed by PJM Settlement for a Load Reduction Event not to exceed \$5,000 in a calendar year. For entities that become Special Members pursuant to this section, the following obligations are waived: (i) the \$1,500 membership application fee set forth in Operating Agreement, Schedule 1, section 1.4.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.4.3; (ii) liability under Operating Agreement, section 15.2 for Member defaults; (iii) thirty days notice for waiting period; and (iv) the requirement for 24/7 control center coverage. In addition, such Members shall not have voting privileges in committees or sector designations, and shall not be permitted to form user groups. On January 1 of a calendar year, a Special Member under this section, at its sole election, may become a Member rather than a Special Member subject to all rules governing being a Member, including regular application and membership fee requirements.

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the

relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

a. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is subject to another contractual obligation or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. A relevant electric distribution company or Load Serving Entity which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation in PJM's Economic Load Response program shall provide to PJM, within the referenced ten Business Day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

b. For end-use customers of an electric distribution company that distributed ~~4~~ million MWh or less in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is permitted to participate in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. If the relevant electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then the electric distribution company or the Load Serving Entity must provide to the Office of the Interconnection within the referenced ten Business Day review period evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with this section 1.5A, including this subsection 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, or relevant electric distribution company and/or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. An end-use

customer that desires not to be simultaneously registered to reduce demand under the Emergency Load Response and Pre-Emergency Load Response Programs and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

1.5A.3.01 Economic Load Response Registrations in Effect as of August 28, 2009

1. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. Effective as of the later of either August 28, 2009 (the effective date of Wholesale Competition in Regions with Organized Electric Markets, Order 719-A, 128 FERC ¶ 61,059 (2009) (“Order 719-A”)) or the effective date of a Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer’s participation in PJM’s Economic Load Response Program, the existing Economic Load Response Participant’s registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated upon an electric distribution company or Load Serving Entity submitting to the Office of the Interconnection either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer’s participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority’s legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation.

i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

2. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. Effective as of August 28, 2009 (the effective date of Order 719-A), an existing Economic Load Response Participant's registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated unless an electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program and provides evidence to the Office of the Interconnection documenting that the permission or conditional permission is pursuant to the laws or regulations of the Relevant Electric Retail Regulatory Authority. If the electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric

distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then, within ten Business Days of verifying such permission or conditional permission, the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

- i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. All registrations submitted to the Office of the Interconnection on or after August 28, 2009, including requests to extend existing registrations, will be processed by the Office of the Interconnection in accordance with the provisions of this section 1.5A, including this subsection 1.5A.3.

1.5A.3. 02 Economic Load Response Regulation Only Registrations.

An Economic Load Response Regulation Only registration allows end-use customer participation in the Regulation market only, and may be submitted by a Curtailment Service Provider that is different than the Curtailment Service Provider that submits an Emergency Load Response Program registration, Pre-Emergency Load Response Program registration or Economic Load Response registration for the same end-use customer. An end-use customer that is registered as Economic Load Response Regulation Only shall not be permitted to register and/or participate in any other Ancillary Service markets at the same time, but may have a second, simultaneously existing Economic Load Response registration to participate in the PJM Interchange Energy Market as set forth in the PJM Manuals.

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7 below, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated

hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. End-use customer reductions in demand must be metered by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), or by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to Operating Agreement, Schedule 1, section 3.3A and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, electric distribution company and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, hourly data reflecting meter readings for each day during which the load reduction occurred and all associated days to determine the reduction must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

Curtailment Service Providers that have end-use customers that will participate in the Regulation market may be permitted to use Sub-metered load data instead of load data at the electric distribution company account number level for Regulation measurement and verification as set forth in the PJM Manuals and subject to the following:

- a. Curtailment Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.
- b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailment Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process.
- c. The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailment Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.
- d. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailment Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the

matter to the Market Monitoring Unit and/or the Federal Energy Regulatory Commission Office of Enforcement.

- b) Curtailment Service Providers shall be responsible for maintaining, or ensuring that Economic Load Response Participants maintain, the capability to receive and act upon an electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Variable-Load Customers.

The loads of an Economic Load Response Participant shall be categorized as variable or non-variable at the time the load is registered, based on hourly load data for the most recent 60 days provided by the Market Participant in the registration process; provided, however, that any alternative means of making such determination when 60 days of data is not available shall be subject to review and approval by the Office of the Interconnection and provided further that 60 days of hourly load data shall not be required on an individual customer basis for non-interval metered residential or Small Commercial Customers that provide Economic Load Response through a direct load control program under which an electric distribution company, Load Serving Entity, or CSP has direct control over such customer's load, without reliance upon any action by such customer to reduce load. Non-Variable Loads shall be those for which the Customer Baseline Load calculation and adjustment methods prescribed by Operating Agreement, Schedule 1, section 3.3A.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.2 and Operating Agreement, Schedule 1, section 3.3A.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.3 result in a relative root mean square hourly error of twenty percent or less compared to the actual hourly loads based on the hourly load data provided in the registration process and using statistical methods prescribed in the PJM Manuals. All other loads shall be Variable Loads.

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The Curtailment Service Provider or PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection

(“Pilot Period”). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the Emergency Load Response Program, Pre-Emergency Load Response Program and the PJM Interchange Energy Market or Synchronized Reserve market. With the sole exception of the requirement for hourly metering as set forth in section 1.5A.4 above, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market, including, without limitation, the Net Benefits Test and the requirement for dispatch by the Office of the Interconnection. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

1.5A.8 Batch Load ~~Economic Load Response Participant Demand Resource~~ Provision of Synchronized Reserve or ~~Day-ahead SchedulingSecondary~~ Reserves.

(a) A Batch Load ~~Economic Load Response Participant Resource Demand Resource~~ may provide Synchronized Reserve or ~~Day-ahead SchedulingSecondary~~ Reserves in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load ~~Economic Load Response Participant Resource Demand Resource~~, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of “Batch Load ~~Economic Load Response Participant Resource Demand Resource~~” pursuant to Operating Agreement, Schedule 1, section 1.3.1A.001 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.3.1A.001. This requirement is a one-time pre-qualification requirement for a Batch Load ~~Economic Load Response Participant Resource Demand Resource~~.

(b) Batch Load ~~Economic Load Response Participant Resources Demand Resources~~ may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour, or up to 20 percent of the total system-wide ~~Day-ahead SchedulingSecondary~~ Reserves requirement in any hour; provided, however, that in the event the Office of the Interconnection determines in its sole discretion that satisfying 20 percent of either such requirement from Batch Load ~~Economic Load Response Participant Resources Demand Resources~~ is causing or may cause a reliability degradation, the Office of the Interconnection may reduce the percentage of either such requirement that may be satisfied by Batch Load ~~Economic Load Response Participant Resources Demand Resources~~ in any hour to as low as 10 percent. This reduction will be effective seven days after the posting of the reduction on the PJM website. Notwithstanding anything to the contrary in this Agreement, as soon as practicable, the Office of the Interconnection unilaterally shall make a filing under section 205 of the Federal Power Act to revise the rules for Batch Load ~~Economic Load Response Participant Resources Demand Resources~~ so as to continue such reduction. The reduction shall remain in effect until the Commission acts upon the Office of the Interconnection’s filing and thereafter if approved or accepted by the Commission.

(c) A Batch Load ~~Economic Load Response Participant Resource Demand Resource~~ that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide ~~Day-ahead SchedulingSecondary~~ Reserves, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of ~~Day-ahead SchedulingSecondary~~ Reserves, until a dispatch instruction that load reductions are no longer required. A Batch Load ~~Economic Load Response Participant Resource Demand Resource~~ that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of ~~Day-ahead Scheduling ReservesSecondary Reserve~~, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of ~~Day-ahead SchedulingSecondary~~ Reserves, until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide ~~Day-ahead SchedulingSecondary~~ Reserves to reduce load.

1.5A.9 Day-ahead and Real-time Energy Market Participation.

Economic Load Response Participants shall be compensated under Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response -Registrations.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 0.1 megawatt of demand response in the ~~Day-Ahead SchedulingSecondary~~ Reserve, Synchronized Reserve or Regulation -markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;

ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day-Ahead Energy Market do not need to share the same Load Serving Entity. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6;

v. If the aggregation will only provide energy to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve. If the aggregation will provide an Ancillary Service to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vi. Each End-Use Customer site must meet the requirements for market participation by an Economic Load Response Participant resource~~demand-resource~~ except for the 0.1 megawatt minimum load reduction requirement for energy or the 0.1 megawatt minimum load reduction requirement for Ancillary Services; and

vii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.10.01 Aggregation for Economic Load Response Regulation Only Registrations

The purpose for aggregation is to allow the participation of end-use customers in the Regulation market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All end-use customers in an aggregation shall be specifically identified;
- ii. All end-use customers in the aggregation must be served by the same electric distribution company and must also be part of the same Transmission Zone; and
- iii. Each end-use customer site must meet the requirements for market participation by an Economic Load Response Participant resource~~demand-resource~~ except for the 0.1 megawatt minimum load reduction requirement for Regulation service.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3 above, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers *and Energy Storage Resources* shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.2B Energy Storage Resources.

Energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market must be Direct Charging Energy. Energy Storage Resources shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and each Applicable Regional Entity, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, Economic Load Response Participant resources~~Demand Resources~~, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner. Market Participants that request additional information or communications system access or connections beyond those which are required by the Office of the Interconnection for reliability in the operation of the LLC or the Office of the Interconnection, including but not limited to PJMnet or Internet SCADA connections, shall be solely responsible for the cost of such additional access and connections and for purchasing, leasing, installing and maintaining any associated facilities and equipment, which shall remain the property of the Market Participant.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with

Operating Agreement, Section 14 ~~of this Agreement~~, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Tariff, section 36.1.1, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement, and as may be further described in the PJM Manuals, for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ economically on the basis of least-cost, security-constrained dispatch and the prices and

operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or ~~Economic Load Response Participant resources~~~~Demand Resources~~ are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or ~~Economic Load Response Participant resources~~~~Demand Resources~~, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the applicable interval Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in the applicable interval, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues from there shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Operating Agreement, Schedule 1, Section 3 ~~to this Schedule~~. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

- (i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its InSchedule and ExSchedule tools.
- (ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

- (iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.
- (iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.
- (v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new InSchedule or ExSchedule reporting by the Market Participant and (ii) terminate all of the Market Participant's InSchedules and ExSchedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the InSchedules and ExSchedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.
- (vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that

are not Dynamic Transfers pursuant to Operating Agreement, Schedule 1, Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through Load Management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

- (i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any Real-time Settlement Interval during the month. For each Real-time Settlement Interval when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that Real-time Settlement Interval hour for all of the energy delivered. Conversely, for each Real-time Settlement Interval when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that Real-time Settlement Interval for all of the energy consumed.
- (ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market

Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Tariff, Part II and shall be charged the hourly rate under Tariff, Schedule 8 for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Tariff, Schedule 1; Tariff, Schedule 1A; Tariff, Schedule 2; Tariff, Schedule 3; Tariff, Schedule 4; Tariff, Schedule 5; Tariff, Schedule 6; Tariff, Schedule 9; and Tariff, Schedule 10 shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

- (iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJM Settlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This subsection shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection, and for additional services they request from the LLC, PJMSettlement or the Office of the Interconnection that are not required for the operation of the LLC or the Office of the Interconnection, in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Entity reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any ~~Economic Load Response Participant resources~~~~Demand Resource~~ subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or ~~Economic Load Response Participant resources~~~~Demand Resources~~ pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or ~~Economic Load Response Participant resources~~~~demand resources~~ located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or Economic Load Response Participant resources~~demand resource~~ shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator. Market Sellers must specify a ramping rate in the Offer Data that is an accurate representation of the resource's capabilities given the confines of the PJM software.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve can be supplied from ~~non-emergency~~ generation resources and/or Economic Load Response Participant resources~~Demand Resources~~ located within the metered boundaries of the PJM Region. A resource is not eligible to provide Synchronized Reserve if its entire output has been designated as emergency energy. All on-line non-emergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve to the Office of the Interconnection, as applicable to the capacity resource's capability to provide these services. During periods for which the Office of the Interconnection has issued a Primary Reserve Warning, Voltage Reduction Warning or Manual Load Dump Warning as described in Tariff, Attachment K Appendix, section 2.5(d) and the parallel provision of Operating Agreement, Schedule 1, section 2.5(d), all other non-emergency generation capacity resources available to provide energy shall have submitted offers for Tier 2 Synchronized Reserves. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary Reserve Requirement and Synchronized Reserve Requirement objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit

the Office of the Interconnection's ability to deliver reserves to a specific geographic area of the PJM Region where reserves are required.

(c) The Synchronized Reserve capability of a generation resource and Economic Load Response Participant resource~~Demand Resource~~ shall be the increase in energy output or load reduction achievable by the generation resource ~~and Demand Resource~~ or Economic Load Response Participant resource within a continuous 10-minute period.

~~(d) — A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.~~

1.7.19A.01 Non-Synchronized Reserve.

(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 are no²t available to provide energy, are not eligible to provide Non-Synchronized Reserve. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve Requirement~~objective~~ for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Non-Synchronized Reserve capability of a generation resource shall be the increase in energy output achievable by the generation resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

~~(d) — The Non-Synchronized Reserve capability of a generation resource shall generally be determined based on the startup and notification time, economic minimum and ramp rate of such resource submitted in the Real-time Energy Market for the Operating Day. If the Generating Market Buyer or Market Seller offering the Non-Synchronized Reserve can demonstrate to the Office of the Interconnection that the Non-Synchronized Reserve capability of a generation~~

~~resource exceeds its calculated value based on market offer data, the Generating Market Buyer or Market Seller and the Office of the Interconnection may agree on a different capability to be used.~~

~~(e) — All Non-Synchronized Reserve offers shall be for \$0.00/MWh.~~

1.7.19A.02 Secondary Reserve.

(a) Secondary Reserve can be supplied from synchronized and non-synchronized generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region, as specified in the PJM Manuals. A resource is not eligible to provide Secondary Reserve if its entire output has been designated as emergency energy or if the resource is not available to provide energy. Generating Market Buyers and Market Sellers offering Secondary Reserve shall comply with applicable standards and requirements for Secondary Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone, as applicable, an amount of Secondary Reserve such that the sum of the Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve meets the respective 30-minute Reserve Requirement for each such Reserve Zone and Reserve Sub-zone, as applicable, and as specified in the PJM Manuals. In accordance with the PJM Manuals, the Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the 30-minute Reserve Requirement in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Secondary Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 30-minute period, minus the increase in energy output or load reduction achievable within a continuous 10-minute period.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve, ~~Non-Synchronized Reserve~~, and ~~Day-ahead Scheduling~~ Secondary Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, Non-Synchronized Reserve market, and ~~Day-ahead Scheduling~~ Secondary Reserves ~~Market~~, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported

to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its Markets Gateway tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or ~~Secondary Day-ahead Scheduling~~ Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new Markets Gateway reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of Markets Gateway schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims

regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported Markets Gateway schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves from PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or ~~Secondary Day-ahead Scheduling~~ Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable, and as may be further described in the PJM Manuals.

(b) Market Sellers selling from generation resources and/or ~~Demand Resources~~ Economic Load Response Participant resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and ~~Demand Resources~~ Economic Load Response Participant resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Economic Load Response Participant resources ~~Demand Resources~~ that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Economic Load Response Participant resources ~~Demand Resources~~; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Economic Load Response Participant resources ~~Demand Resources~~ are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

(h) Market Participants engaging in Coordinated External Transactions shall provide to the Office of the Interconnection the information required to be specified in a CTS Interface Bid, in accordance with the procedures of Tariff, Attachment K-Appendix, section 1.13 and the parallel provisions of Operating Agreement, Schedule 1, section 1.13.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) (i) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, ~~or Transmission Customers that deviate from the transmission uses,~~ scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, ~~or pay Transmission Congestion Charges and Transmission Loss Charges,~~ for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(ii) In the Real-time Energy Market, Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to pay Transmission Congestion Charges and Transmission Loss Charges for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection

determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Operating Agreement, Schedule 1, Ssection 1.13 ~~of this Schedule 1 of this Agreement~~. Scheduling shall be conducted as specified in Ssection 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, Ssections 3.2.3 and Operating Agreement, Schedule 1, section 6.6 ~~hereof~~.

1.10.1A Day-ahead and Real-time Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed \$2,000/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to \$2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

- i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;
- ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Operating Agreement, Schedule 1, Section 1.12; and
- iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and

sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- \$50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c-2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to \$2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, -or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this ~~S~~section 1.10.1A(d), ~~s~~Section 1.10.9B below, Operating Agreement, Schedule 2 ~~of the Operating Agreement~~, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

- i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This

includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

- ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.
- iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.
- iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d), and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

- i) Shall specify the Generation Capacity Resource or Economic Load Response Participant resource ~~Demand Resource~~ and energy or demand reduction amount, respectively, for each clock hour in the offer period;
- ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
- iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; ~~and~~ (12) emergency maximum MW; (13) Synchronized Reserve maximum

MW; (14) Secondary Reserve maximum MW; and (15) condense to generation time constraints, and may specify offer parameters for Economic Load Response Participant resource ~~Demand Resources~~ for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

- iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;
- v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;
- vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;
- vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;
- viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above \$1,000/megawatt-hour and less than or equal to \$2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than \$2,000/megawatt-hour, then its market-based offer must be less than or equal to \$2,000/megawatt-hour; and
- ix) Shall not exceed a demand reduction offer price of \$1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above \$1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than \$2,000/megawatt-hour; and

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Tariff, Attachment DD-1, Section A.2 ~~of Attachment DD-1 of the Tariff~~ and the parallel provision of RAA, Schedule 6 ~~of the RAA~~, \$1,000~~849~~/megawatt-hour, ~~plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus \$1.00;~~

b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, Section A.2 ~~of Attachment DD-1 of the Tariff~~ and the parallel provision of RAA, Schedule 6 ~~of the RAA~~, \$1,000~~425~~/megawatt-hour, ~~plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and~~

c) an approved 120 minute lead time, pursuant to Tariff, Attachment DD-1, Section A.2 ~~of Attachment DD-1 of the Tariff~~ and the parallel provisions of RAA, Schedule 6 ~~of the RAA~~, \$1,100/megawatt-hour; and

~~x~~i) Shall not exceed an energy offer price of \$0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed \$100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;

- ii. The cost increase (in $\$/\Delta\text{MW}$) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and
- iii. An adder of up to \$12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, Sections 3.2.3 and Operating Agreement, Schedule 1, section 6.6 hereof.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink

designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) (i) Offers to Supply Synchronized and Non-Synchronized Reserves By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (A) are capable of providing Synchronized Reserve or Non-Synchronized Reserve, as specified in the PJM Manuals, (B) are located within the metered boundaries of the PJM Region, and (C) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve or Non-Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve and Non-Synchronized Reserve, as applicable.

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be

recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in \$/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of implementation of this rule the expected value of the penalty shall be \$0.02/MWh, and for the period from the second month after implementation through the second January 1 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

(4) All Non-Synchronized Reserve offers shall be for \$0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) of this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized Reserve capability as part of their offer into the Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B) Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum; and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(iii) Determination of Available Non-Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available Non-Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Such hydroelectric generation resources or Energy Storage Resources may submit offers for their available Non-Synchronized Reserve capability as part of their offer into the Non-Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Non-Synchronized Reserve offer which specifies the MW of available Non-Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An off-line generation resource's available Non-Synchronized Reserve capability shall be determined in accordance with the PJM Manuals and based on the following offer parameters submitted as part of the resource's energy offer:

(A) startup time; (B) notification time; (C) ramp rate; (D) Economic Minimum; and (E) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Non-Synchronized Reserves above its Synchronized Reserve maximum MW.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

(1) Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve may submit offers to supply Synchronized Reserve from such resources, where such offers A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, as determined in accordance with section 1.10.1A(j)(i)(3) above. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts; (ii) the Day-ahead Locational

Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, ~~start-up~~shutdown costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of an Economic Load Response Participant resource~~Demand Resource~~ that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Economic Load Response Participant resource~~Demand Resource~~. The submission of demand reduction bids for Economic Load Response Participant resource~~Demand Resource~~ increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. An Economic Load Response Participant resource~~Demand Resource~~ that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Economic Load Response Participant resources~~Demand Resources~~ to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes (less its energy output achievable within ten minutes) from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources located within the metered boundaries of the PJM Region that submit offers for the supply of energy into the

Day-ahead Energy Market and/or Real-time Energy Market and are capable of providing Secondary Reserve, as specified in the PJM Manuals, shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall be for \$0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available Synchronized Reserve capability; and the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating

configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(B) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(C) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(iii) Offers to Supply Secondary Reserves by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wishes to make their resources available to supply Secondary Reserve shall submit offers to supply Secondary Reserve from such resources, where such offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for \$0.00/MWh. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer

Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

~~Market Sellers providing Day-ahead Scheduling Reserves Resources shall submit in the Day-ahead Scheduling Reserves Market: 1) a price offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit Day-ahead Scheduling Reserves pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The megawatt quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.~~

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = -greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to ~~S~~sections 1.10.9 below or Operating Agreement, Schedule 1, section 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in ~~s~~Section 1.10.1A above. Hydropower units can only be pool-scheduled if they are pumped

storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Operating Agreement, Schedule 1, Section 3 ~~of this Schedule 1~~. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which ~~offer~~ must equal or exceed 0.1 megawatts, in minimum increments of 0.1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market and/or the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve or Non-Synchronized Reserve.

(fe) For energy, Hhydropower units, excluding pumped storage units, may only be self-scheduled.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

(c) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

- (i) enter its election on OASIS by 11:00 a.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and
- (ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in ~~s~~Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this ~~s~~Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this ~~S~~section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in ~~s~~Section 1.10.1A above that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by [Operating Agreement, Schedule 1](#), section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in [Section 1.10.8\(b\)](#), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated

projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJM Settlement and Market Sellers shall be paid by PJM Settlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJM Settlement and Market Sellers shall pay PJM Settlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Operating Agreement, Schedule 1, Section 3.3A ~~of this Schedule~~. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Operating Agreement, Schedule 1, Sections 2.4 and Operating Agreement, Schedule 1, section 2.5 ~~hereof~~.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market or Day-ahead Ancillary Services Markets, or the Real-time Energy Market, or Real-time Ancillary Services Markets ~~or Day-ahead Scheduling Reserve Market~~ after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the ~~Ancillary Services Markets and~~ Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the ~~Day-ahead Scheduling Reserve Market and~~ Day-ahead Energy Market and Day-ahead Ancillary Services Markets. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the ~~Ancillary Services Markets and~~ Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the ~~Day-ahead Scheduling Reserve Market and the~~ Day-ahead Energy Market and Day-ahead Ancillary Services Markets. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the ~~Ancillary Services Markets, Day-ahead Energy Market, and~~ Real-time Energy Market, and Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets ~~and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market~~. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth

above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Operating Agreement, Section 18.17.1 ~~of the PJM Operating Agreement~~, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A ~~of this~~ Schedule below:

- i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;
- ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or
- iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or
- iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously

designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this ~~S~~section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market

Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost, and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; ~~and~~ (6) fixed output indicator; (7) Synchronized Reserve maximum MW; and (8) Secondary Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy, Secondary Reserve, Synchronized Reserve, Non-Synchronized Reserve, or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) Synchronized Reserve maximum MW; (7) Secondary Reserve maximum MW; and ~~(68)~~ for Real-time Offers only, (i) notification time; (ii) ramp rate; and (iii) for uncommitted hours only, Minimum Run Time.

(c) For Economic Load Response Participant resource ~~Demand Resource~~ offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, ~~ramp rate~~ maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the entity controlling a pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Operating Agreement, Schedule 1, Section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Economic Load Response Participant resources ~~Demand Resources~~ offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Economic Load Response Participant resources ~~Demand Resource~~'s regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Economic Load Response Participant resources ~~Demand Resources~~ will be zero.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load-energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve Obligation from its own generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve, or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Operating Agreement, Schedule 1, Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve ~~from the least-cost alternatives available~~ from either available pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ as needed to meet the Synchronized Reserve ~~Requirements~~ of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Market Buyers. The Office of the Interconnection shall clear both the Day-ahead Synchronized Reserve Market and the Real-time Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Synchronized Reserve Market. Resources ~~offering to sell Synchronized Reserve~~ shall be ~~cleared~~selected to provide Synchronized Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource~~Demand Resource~~'s Synchronized Reserve offer and the ~~estimated unit specific opportunity cost of the resource product substitution cost between~~ providing Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy, Operating Reserves, and of meeting the Synchronized Reserve Requirement, and other ancillary services Primary Reserve Requirement, 30-minute Reserve Requirement and Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market shall be committed to provide Synchronized Reserve in the Real-time Synchronized Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product. ~~Estimated unit specific opportunity costs for generation resources shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the generation resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.~~ For

any given interval for each Reserve Zone or Reserve Sub-zone, the Office of the Interconnection shall clear Economic Load Response Participant resources in an amount less than or equal to 50 percent of the Minimum Synchronized Reserve Requirement.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources~~Demand Resources~~ for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Economic Load Response Participant resources ~~Demand Resources~~ from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying load energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources capable of providing Non-Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Non-Synchronized Reserve, or by purchases from the PJM Non-Synchronized Reserve Market at the rates set forth in Operating Agreement, Schedule 1, Section 3.2.3A.001. PJM Settlement shall be the Counterparty to the purchases and sales of Non-Synchronized Reserve in the PJM Interchange Energy Market; provided that PJM Settlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-supply of generation resources by a Market Buyer to satisfy its Non-Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from ~~either~~ pool-scheduled generation resources as needed to ensure the Primary Reserve requirement of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the ~~Market Buyers~~ resources providing Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Non-Synchronized Reserve Market and the Real-time Non-Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Non-Synchronized Reserve Market. Resources eligible to sell Non-Synchronized Reserve shall be selected-cleared to provide Non-Synchronized Reserve on the basis of each resource's product substitution cost ~~each generation resource's estimated between providing unit specific opportunity cost of the resource providing~~ Non-Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the, Synchronized Reserve Requirement, Primary Reserve Requirement, 30-minute Reserve Requirement, and Regulation Requirement. ~~Operating Reserves, Synchronized Reserve, and other ancillary services. Estimated unit specific opportunity costs for generation resources not providing energy because they are providing Non-~~

~~Synchronized Reserve shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.~~

(c) The Office of the Interconnection shall dispatch generation resources for Non-Synchronized Reserve by sending Non-Synchronized Reserve instructions to generation resources from which Non-Synchronized Reserve is available, in accordance with the PJM Manuals. Market Sellers shall comply with Non-Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Non-Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energyload in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4C Secondary Reserve.

(a) A Market Buyer may satisfy its Secondary Reserve Obligation by contractual arrangements with other Market Participants able to provide Secondary Reserve, or by purchases from the PJM Secondary Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.01. PJMSettlement shall be the Counterparty to the purchases and sales of Secondary Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants.

(b) The Office of the Interconnection shall obtain Secondary Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 30-minute Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by resources providing Synchronized Reserve and resources providing Non-Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Secondary Reserve Market and the Real-time Secondary Reserve Market in accordance with the applicable Operating Reserve Demand Curves established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market and the offers submitted in the Secondary Reserve Market. Resources shall be cleared to provide Secondary Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Secondary Reserve offer and the product substitution cost between providing Secondary Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirement, Primary Reserve Requirement, 30-minute Reserve Requirement and Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes greater but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater

than one hour, and which receives a commitment to provide Secondary Reserve in the Day-ahead Secondary Reserve Market shall be committed to provide Secondary Reserve in the Real-time Secondary Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product. For any given interval for each Reserve Zone or Reserve Sub-zone, the Office of the Interconnection shall clear Economic Load Response Participant resources in an amount less than or equal to 50 percent of the Minimum 30-minute Reserve Requirement.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Secondary Reserve by sending Secondary Reserve instructions to generation resources and/or Economic Load Response Participant resources from which Secondary Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

The Office of the Interconnection shall update the information posted on the PJM Open Access Same-time Information System to reflect its dispatch of generation resources.

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained economic dispatch, which is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by [Operating Agreement, Schedule 1](#), section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load buses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers, except that generation resources will be dispatched in economic merit order but limited to \$2,000/megawatt-hour for purposes of calculating Locational Marginal Prices. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in [Operating Agreement, Schedule 1, Ssection 2.3](#)~~below~~. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants, Pre-Emergency Load Response [Program](#) participants and Emergency Load Response [Program](#) participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in [Operating Agreement, Schedule 1, Ssection 2.4](#)~~below~~, every qualified offer for demand reduction and of energy by a Market Seller from resources that are dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified offers from Economic Load Response Participants in either the Day-ahead or Real-time Energy Markets or from [participants in either the](#) Emergency Load Response [Program and-or](#) Pre-Emergency Load Response ~~participants-Program~~ in the Real-time Energy Market.

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the Office of the Interconnection shall determine the least costly means of obtaining energy to serve the

next increment of load at each bus in the PJM Region, in the manner described in Operating Agreement, Schedule 1, Section 2.5~~below~~. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

(d) (i) The Office of the Interconnection shall use its day-ahead market clearing software to forecast if the Office of the Interconnection will experience a shortage of the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement and/or the Minimum Synchronized Reserve Requirement as further described in the PJM Manuals. If the day-ahead market clearing software forecasts that a shortage of any of the minimum reserve requirement(s) exists, the Office of the Interconnection shall implement shortage pricing through the inclusion of the applicable Reserve Penalty Factor(s) in the Day-ahead Locational Marginal Prices. Shortage pricing shall exist until the day-ahead market clearing software is able to meet the specified minimum reserve requirements.

(ii) The Office of the Interconnection shall use its real-time security-constrained economic dispatch software program to determine if the Office of the Interconnection is experiencing a ~~shortage of the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement and/or the Minimum Synchronized Reserve Requirement~~ as further described in the PJM Manuals. If the real-time security-constrained economic dispatch software program determines that a ~~shortage of any of the minimum reserve requirement(s) Primary Reserve shortage and/or a Synchronized Reserve shortage~~ exists, ~~the~~ the Office of the Interconnection shall implement shortage pricing through the inclusion of the applicable Reserve Penalty Factor(s) in the Real-Time Locational Marginal Price software program. Shortage pricing shall exist until the real-time security-constrained economic dispatch solution is able to meet the specified minimum reserve requirements and there is no Voltage Reduction Action or Manual Load Dump Action in effect. If a shortage of the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement and/or the Minimum Synchronized Reserve Requirement ~~Primary Reserve shortage and/or Synchronized Reserve shortage~~ exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem with or malfunction of the security-constrained economic dispatch software program, including but not limited to program failures or data input failures, the Office of the Interconnection will utilize the best available alternate data sources to determine if a Reserve Zone or Reserve Sub-zone is experiencing a shortage of the applicable minimum reserve requirement~~Primary Reserve shortage and/or a Synchronized Reserve shortage~~.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and utilized in the PJM security-constrained economic dispatch algorithm and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Operating Agreement, Schedule 1, Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made 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 Operating Reserve Demand Curves~~Reserve Penalty Factors~~, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by an Economic Load Response Participant resource~~Demand-Resource~~, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by an Economic Load Response Participant resource~~Demand-Resource~~, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by an Economic Load Response Participant resource~~Demand-Resource~~ based on the effect of increased generation from or consumption by the resource on transmission losses. ~~The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints, and marginal loss impact.~~

(b) ~~The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the applicable Operating Reserve Demand Curves. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange. If all reserve requirements in every modeled Reserve Zone and Reserve Sub-zone can be met at prices less than or equal to the applicable Reserve Penalty Factor for those reserve requirements, real-time Locational Marginal Prices shall be calculated as described in Section 2.5(a) above and no Reserve Penalty Factor(s) shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When a reserve requirement cannot be met at a price less than or equal to the applicable Reserve Penalty Factor(s) associated with a Reserve Zone or Reserve Sub-zone, the real-time Locational Marginal Prices shall be calculated by incorporating the applicable~~

~~Reserve Penalty Factor(s) for the deficient reserve requirement as the lost opportunity cost impact of the deficient reserve requirement, and the components of Locational Marginal Prices referenced in Section 2.5(a) above shall be calculated as described below.~~

(c) The Office of the Interconnection shall issue day-ahead alerts to PJM Members of the possible need to use emergency procedures during the following Operating Day. Such emergency procedures may be required to alleviate real-time emergency conditions such as a transmission emergency or potential reserve shortage. The alerts issued by the Office of the Interconnection may include, but are not limited to, the Maximum Emergency Generation Alert, Primary Reserve Alert and/or Voltage Reduction Alert. These alerts shall be issued to keep all affected system personnel informed of the forecasted status of the PJM bulk power system. The Office of the Interconnection shall notify PJM Members of all alerts and the cancellation thereof via the methods described in the PJM Manuals. The alerts shall be issued as soon as practicable to allow PJM Members sufficient time to prepare for such operating conditions. The day-ahead alerts issued by the Office of the Interconnection are for informational purposes only and by themselves will not impact price calculation during the Operating Day.

(d) The Office of the Interconnection shall issue a warning of impending operating reserve shortage and other emergency conditions in real-time to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM bulk power system. Such warnings will generally precede any associated action taken to address the shortage conditions. The Office of the Interconnection shall notify PJM Members of the issuance and cancellation of emergency procedures via the methods described in the PJM Manuals. The warnings that the Office of the Interconnection may issue include, but are not limited to, the Primary Reserve Warning, Voltage Reduction Warning, and Manual Load Dump Warning.

The purpose of the Primary Reserve Warning is to warn members that the available Primary Reserve may be less than the Minimum Primary Reserve Requirement. If the Primary Reserve shortage condition was determined as described in Operating Agreement, Schedule 1, Section 2.2(d)~~above~~, the applicable Reserve Penalty Factor is incorporated into the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable.

The purpose of the Voltage Reduction Warning is to warn PJM Members that the available Synchronized Reserve may be less than the Minimum Synchronized Reserve Requirement and that a voltage reduction may be required. Following the Voltage Reduction Warning, the Office of the Interconnection may issue a Voltage Reduction Action during which it directs PJM Members to initiate a voltage reduction. If the Office of the Interconnection issues a Voltage Reduction Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement and ~~the Reserve Penalty Factor for the Minimum~~ Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price as applicable. The Reserve Penalty Factors for the Minimum 30-minute Reserve Requirement, ~~Reserve Penalty Factor for the Minimum~~ Primary Reserve Requirement and ~~the Reserve Penalty Factor for the Minimum~~ Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing

Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price calculation, as applicable, until the Voltage Reduction Action has been terminated.

The purpose of the Manual Load Dump Warning is to warn members that dumping load may be necessary to maintain reliability. Following the Manual Load Dump Warning, the Office of the Interconnection may commence a Manual Load Dump Action during which it directs PJM Members to initiate a manual load dump pursuant to the procedures described in the PJM Manuals. If the Office of the Interconnection issues a Manual Load Dump Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factor_s for the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement and ~~the Reserve Penalty Factor for the Minimum~~ Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price as applicable. The Reserve Penalty Factors for the Minimum 30-minute Reserve Requirement, ~~Reserve Penalty Factor for the Minimum~~ Primary Reserve Requirement and ~~the Reserve Penalty Factor for the Minimum~~ Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price calculation, as applicable, until the Manual Load Dump Action has been terminated.

Shortage pricing will be terminated in a Reserve Zone or Reserve Sub-Zone when demand and minimum reserve requirements can be fully satisfied with generation and ~~demand-response resources~~ Economic Load Response Participant resources and any Voltage Reduction Action and/or Manual Load Dump Action taken for that Reserve Zone or Reserve Sub-Zone has also been terminated.

(e) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing the Real-time Prices based on system conditions during the preceding interval.

2.6 Calculation of Day-ahead Prices.

(a) For the Day-ahead Energy Market, day-ahead Locational Marginal Prices shall be determined on the basis of the least-cost, security-constrained dispatch, model flows and system conditions resulting from the load specifications (including PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads that they serve), offers for generation, dispatchable load, Increment Offers, Decrement Bids, offers for demand reductions, and bilateral transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Such prices shall be determined in accordance with the provisions of this ~~S~~section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy and reserve costs, given scheduled system conditions, scheduled transmission outages, ~~and~~ any transmission limitations that may exist, and a set of Operating Reserve Demand Curves. This calculation shall be made by applying a joint optimization of energy and reserves, given scheduled system conditions, a set of energy offers, a set of reserve offers, a set of Operating Reserve Demand Curves, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing consumption by ~~an~~ Economic Load Response Participant resource~~Demand Resource~~, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by ~~an~~ Economic Load Response Participant resource~~Demand Resource~~ based on the effect of increased generation from or consumption by the resource on transmission line losses. ~~The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Day-ahead Price at that bus.~~

(b) The day-ahead Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the impact of the applicable Operating Reserve Demand Curves. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Operating Agreement, Schedule 1, Section 2 ~~of this Schedule~~.

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A ~~of this Schedule~~ shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market performance clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

(b) Each Market Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to ~~Section 3.2.2A.1 of this Schedule below~~, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 ~~of this Schedule below~~ shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in Operating Agreement, Schedule 1, section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the

generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Economic Load Response Participant resources ~~Demand Resources~~ to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour in accordance with the PJM Manuals and below.

The unit-specific opportunity cost incurred during the Real-time Settlement Interval in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Economic Load Response Participant resources~~Demand Resources~~ to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during each of the preceding three Real-time Settlement Intervals of the shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the preceding three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding three Real-time Settlement Intervals of the shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating Real-time Settlement Interval) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following three Real-time Settlement Intervals of the shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the following three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following three Real-time Settlement Intervals of the shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy

Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the Regulation market performance-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the Regulation market performance-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the Regulation market performance-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the Regulation market capability-clearing price for each Regulation Zone by subtracting the Regulation market performance-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the Regulation market capability-clearing price for that market Real-time Settlement Interval.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. Resources following the dynamic Regulation signal which have a unit-specific benefits factor less than 0.1 will not be considered for the purposes of committing resources. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta, \delta+5 \text{ Min})};$$

$\delta=0 \text{ to } 5 \text{ Min}$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs} ((\delta - 5 \text{ Minutes}) / (5 \text{ Minutes})).$$

The Office of the Interconnection shall calculate an energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ϵ) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs} (\text{Error});$$

$$\text{Error} = \text{Average of Abs} ((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})); \text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score).

The historic accuracy score will be based on a rolling average of the Real-time Settlement Interval accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1A(e) ~~of this Schedule~~. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three

suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Tariff, Attachment K-Appendix, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 and the parallel provision of Operating Agreement, Schedule 1, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 does not meet the Minimum Synchronized Reserve Requirement, the Minimum Primary Reserve Requirement, and the Minimum 30-minute Day-ahead Scheduling-Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Tariff, Attachment K-Appendix, section 1.7.17 and the parallel provision of Operating Agreement, Schedule 1, section 1.7.17, and Tariff, Attachment K-Appendix, section 1.10 and the parallel provision of Operating Agreement, Schedule 1, section 1.10. In addition, the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market~~Day-ahead Scheduling-Reserves Requirement~~.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources~~Demand Resources~~) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations or real-time load share plus exports,

pursuant to Section 3.2.3(p) below, depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day. *Allocation to real-time load share under this subsection (b) shall not apply to Direct Charging Energy.*

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant

Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by ~~S~~section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with ~~S~~section 3.2.3(b) plus any unallocated charges from ~~s~~Section 3.2.3(h) and Operating Agreement, Schedule 1, 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load ((a) net of Behind The Meter Generation expected to be operating, but not to be less than zero; and (b) *excluding Direct Charging Energy*) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Operating Agreement, Schedule 1, Ssection 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A ~~of the PJM Tariff~~. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by

the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources~~Demand Resources~~); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources~~Demand Resources~~). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources~~Demand Resources~~) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or charge for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Economic Load Response Participant resources~~Demand Resources~~) costs for generation resources.

Except as provided in ~~S~~section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to ~~s~~Section 3.2.3(b), and less the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below any amounts credited for Non-Synchronized Reserve in excess of the Non-Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for providing Reactive Services as specified in ~~S~~section 3.2.3B, and less the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and ~~Real-time Settlement Interval share of the Day-ahead Scheduling~~Secondary Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding Real-time Settlement Interval(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and ~~Day-ahead Scheduling~~Secondary Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Operating Agreement, Schedule 1, Ssection 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC d~~Deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order,~~ times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3(f).
- (ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:
 - 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A*B) - (C+D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or
 - 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

~~Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market shall not be eligible to receive compensation for lost opportunity costs under any applicable provisions of Schedule 1 of this Agreement.~~

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, Section 1.10.3-(c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output

due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the ~~real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override),~~ shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the ~~LOC dDeviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order,~~ times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as (A*B) - C.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with ~~Operating Agreement, Schedule 1, Section 1.10.2(d),~~ such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in ~~Tariff, Schedule 6A of the PJM Tariff,~~ shall be allocated and charged to each Market Participant based on their daily total of hourly deviations determined in accordance with the following equation:

$$\sum_h (A + B + C)$$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12 ~~of this Schedule~~ are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A ~~of this Schedule~~ shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A ~~of the PJM Tariff~~.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) ~~below of this Schedule~~, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If

deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of Supply or Demand deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b)

excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, sSection 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared (“Maximum Generation Emergency Alert”); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by sSection 3.2.3(b) or Ssection 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as “MaxGen Conditions”). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Operating Agreement, Schedule 2-of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Operating Agreement, Schedule 1, Ssection 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Operating Agreement, Schedule 1, Ssection 1.9.7(b); provided, however, that the Market Seller must return to compliance with Operating Agreement, Schedule 1, Ssection 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller’s lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to sSection 3.2.3(e) plus the Real-time Energy Market revenues for the Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time Settlement Intervals required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with ~~S~~section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to \$1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with ~~S~~section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed \$1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to ~~s~~Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described below and in the PJM Manuals.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

- (i) real-time economic minimum $\leq$ 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum $\geq$ 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\text{Ramp\_Request}_t = \frac{(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSLAtime}_{t-1})}$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1} \right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value for each Real-time Settlement Interval. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW for each Real-time Settlement Interval.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its Real-time Settlement Interval MWh is within 5% of the Real-time Settlement Interval ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined for each Real-time Settlement Interval in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.
- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – UDS LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.
- If a resource is not following dispatch and its % off Dispatch is $> 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

(o-1) Dispatchable ~~e~~Economic ~~l~~oad ~~reduction-Response Participant~~ resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction

resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in Operating Agreement, Schedule 1, section 3.3A-~~of this Appendix~~. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Operating Agreement, Schedule 1, ~~sSection 3.2.3(h)-of Schedule 1 of this Agreement~~ except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A-~~of the PJM Tariff~~, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day. *Allocation to real-time load share under this subsection (p) shall not apply to Direct Charging Energy.*

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceeds the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Operating Agreement, Schedule 1, s~~Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement~~ to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC, OVEC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with s~~Section 3.2.3(p)~~. *Allocation to real-time load share under this subsection (q)(i) shall not apply to Direct Charging Energy.*

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Operating Agreement, Schedule 1, S~~section 3.2.3(q)(i) of Schedule 1 of this Agreement~~. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation

charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with ~~S~~section 3.2.3(p). *Allocation to real-time load share under this subsection (q)(ii) shall not apply to Direct Charging Energy.*

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than \$1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2 ~~of the Operating Agreement~~ and PJM Manual 15, but are not verified at the time of dispatch of the resource under Operating Agreement, Schedule 1, section 6.4.3 ~~of this Schedule~~, or greater than \$2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2 ~~of the Operating Agreement~~, and PJM Manual 15, will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than \$2,000/MWh, and costs greater than \$1,000/MWh which were not verified at the time of dispatch of the resource under Operating Agreement, Schedule 1, section 6.4.3 ~~of this Schedule~~. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's ~~s-with an~~ hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized

~~Reserve as defined in sections 3.2.3A(b)(i) and (ii) below the quantity of Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.~~

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection, ~~in excess of its hourly Synchronized Reserve Obligation,~~ shall be credited as follows:

~~i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event (“Tier 1 Synchronized Reserve”) shall be at the Synchronized Energy Premium Price, as described in 3.2.3A (c), with the exception of those Real-time Settlement Intervals in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur in a Real-time Settlement Interval.~~

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions (“Tier 2 Synchronized Reserve”) shall be equal to the product of the higher of (i) the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide, or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection to a Synchronized Reserve Event in a Real-time Settlement Interval in accordance with procedures specified in the PJM Manuals.

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) — Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event in a Real-time Settlement Interval initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]The Synchronized Reserve Energy Premium Price is an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using

Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

(ii) For the Real-time Synchronized Reserve Market, The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. ~~The hourly Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price.~~ Each 5-minute clearing price shall be calculated as the ~~marginal price~~cost of serving the next increment of demand for Synchronized Reserve in ~~each~~ Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using inclusive of Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute. ~~When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone.~~

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the ~~5-minute Real-time Synchronized Reserve Market e~~Clearing ~~p~~Price shall be the sum of the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirement, Minimum Primary Reserve Requirement and the Minimum Synchronized Reserve Requirement for ~~each that~~ Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the Minimum Synchronized Reserve Requirement shall be ~~\$8502,000~~/MWh.

~~The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be \$300/MWh.~~

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding ~~\$24,000~~/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the

Interconnection will also review this analysis to determine whether any changes to the Synchronized-Reserve Penalty Factors on the Operating Reserve Demand Curves for Synchronized Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For each Real-time Settlement Interval and for determining the 5-minute Synchronized Reserve Market eClearing pPrice in each hour of the Day-ahead Synchronized Reserve Market, the estimated unitresource-specific opportunity cost for a generation resource or Economic Load Response Participant resource will shall be determined in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where

A = The Locational Marginal Price at the generation bus for the generation resource;

B = The megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer;

C = The deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order; and

D = The difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve energy dispatch set point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, The opportunity costs for a Demand Resource shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource)

in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a ~~generation~~ resource, except a generation resource that is operating as a synchronous condenser, selected to provide Tier 2 Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a ~~generation~~ resource shall be determined for each operating hour Real-time Settlement Interval that the Office of the Interconnection requires a ~~generation~~ resource to provide Tier 2 Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - (C - D)$$

Where:

~~A = The megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer;~~

~~B - A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;~~

$E-B$ = The deviation of the ~~generation~~ resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment ~~follow the Office of the Interconnection's signals and instructions from the generation resource's expected energy output level or load reduction level~~ if it had been ~~assigned~~dispatched in economic merit order to provide energy or reduce load; and

$D-C$ = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

$(A \times B) - C$

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, capped at the amount of Synchronized Reserve the resource responded during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the

Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A] plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and ~~the~~ the difference between the real-time Locational Marginal Price at the generation bus for the ~~generation hydroelectric~~ resource and the average real-time offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment ~~is greater than the offer price for energy from the generation resource.~~

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B + C + D) - (E + F + G + H)$$

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves Demand Resource shall be zero.

(g) [Reserved for future use]Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Participant in excess of that Market Participant's Synchronized Reserve Obligation, the Tier 1 Synchronized Reserve that is not utilized to fulfill the Market Participant's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 For each operating hour, the sum of the Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) abovein a Real-time Settlement Interval in excess of the Synchronized Reserve Market Clearing Price in that Real-time Settlement Interval shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its real-time purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) [Reserved for future use]In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during a Real-time Settlement Interval than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that Real-time Settlement Interval due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Economic Load Response Participant resource Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve in real-time fails to provide the assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 charged at the Real-time Synchronized Reserve Market Clearing Price capacity for the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource, in excess of the amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Tier 2 Synchronized Reserve in real-time on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for ~~Tier-2~~ Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of ~~Tier-2~~ Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide ~~Tier-2~~ Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more ~~Tier-2~~ Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less ~~Tier-2~~ Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of ~~Tier-2~~ Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price ~~by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts,~~ for all intervals the resource was assigned or self-scheduled to provide ~~Tier-2~~ Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of ~~Tier-2~~ Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts ~~less any Tier-1 Synchronized Reserve applied to its Synchronized Reserve Obligation~~ in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or an Economic Load Response Participant resource ~~Demand Resource~~, except for Batch Load Economic Load Response Participant Resources ~~Demand Resources~~ covered by section 3.2.3A(l) below, is the difference between the generation resource's output or the Economic Load Response Participant resource ~~Demand Resource~~'s consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow

for small fluctuations and possible telemetry delays, generation resource output or Economic Load Response Participant resource Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant resource Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to an Economic Load Response Participant resource Demand Resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant resource Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Economic Load Response Participant Resource Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Economic Load Response Participant Resource Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant Resource Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant Resource Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.¬

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's ~~with an~~ hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below~~the quantity of Non-Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.~~

(b) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows: Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the Operating Reserve Demand Curve for Primary Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute.

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. ~~The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price.~~ Each 5-minute clearing price shall be calculated as the ~~marginal price cost of serving the next increment of demand for Primary Reserve procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone, inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement~~ determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the Operating Reserve Demand Curve for Primary Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute. ~~When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone.~~

If the Office of the Interconnection has initiated a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute Real-time Non-Synchronized Reserve Market eClearing pPrice shall be the sum of the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirement and Reserve Penalty

~~Factor for the Minimum Primary Reserve Requirement for each Reserve Zone or Reserve Sub-zone to which it can contribute that Reserve Zone or Reserve Sub-zone.~~

~~(iii) The Reserve Penalty Factor for the Synchronized Minimum Primary Reserve Requirement shall be \$2,000850/MWh.~~

~~The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be \$300/MWh.~~

~~(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$12,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary-Reserve Penalty Factors on the Operating Reserve Demand Curves for Primary Reserve are warranted for subsequent Delivery Year(s).~~

~~(d) (i) For each Real-time Settlement Interval and for determining the 5-minute Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non-Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero. determined in accordance with the following equation:~~

~~(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.~~

~~A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:~~

~~(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;~~

~~(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;~~

~~(C) A resource's Final Offer is less than its Committed Offer;~~

~~(D) A resource trips offline or otherwise becomes unavailable in real-time; or~~

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$\text{(zero)} - (A + B + C + D)$$

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

$$\text{(A x B)} - C$$

Where:

A = The deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order;

B = The Locational Marginal Price at the generation bus for the generation resource; and

C = The applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) [Reserved for future use] In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be in accordance with the following equation:

$$\text{(A x B)} - C$$

Where:

~~A = The deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order;~~

~~B = The Locational Marginal Price at the generation bus for the generation resource; and~~

~~C = The applicable offer for energy from the generation resource in the PJM Interchange Energy Market.~~

(f) ~~For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above. Any amounts credited for Non-Synchronized Reserve in a Real-time Settlement Interval in excess of the Non-Synchronized Reserve Market Clearing Price in that Real-time Settlement Interval shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its~~ real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous Real-time Settlement Interval the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 ~~Day-ahead Scheduling~~ Secondary Reserves.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral

agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below. The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJM Settlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJM Settlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows: A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the cleared megawatt quantity of Day-ahead Scheduling Reserves in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue

Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]~~To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:~~

~~(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.~~

~~(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.~~

~~(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.~~

~~(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes~~

~~after the time of the “ending MW usage” in which the Batch Load Demand Resource’s consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.~~

~~Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.~~

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for 30-minute Reserve for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for 30-minute Reserve for that Reserve Zone or Reserve Sub-zone plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the sum of the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirements for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the Minimum 30-minute Reserve Requirement shall be \$2000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for 30-minute Reserve are warranted for subsequent Delivery Year(s).

~~The hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement ("Base Day-ahead Scheduling Reserves credits") shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources, and are allocated as Base Day-ahead Scheduling Reserves charges per paragraph (i) below. The hourly credits paid to Day-ahead Scheduling Reserve Resources satisfying the Additional Day-ahead Scheduling Reserve Requirement ("Additional Day-ahead Scheduling Reserves credits") shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.~~

- ~~(i) — A Market Participant's Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant's hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying to PJM. The hourly obligation is equal to the Market Participant's load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant's total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant's hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.~~
- ~~(ii) — Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy~~

~~Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.~~

- (e) (i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

- (ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

~~If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.~~

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

$$\underline{(A \times B) - C}$$

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary

Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero,

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B) - (C + D + E + F)$$

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and

continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference

between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

(a) Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing 30-minute Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet reliability requirements in light of supply and demand uncertainties. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with subsection (b) and the PJM Manuals.

(b) Methodology for Establishing Operating Reserve Demand Curves

For each three-month season, Winter (December through February), Spring (March through May), Summer (June through August), and Fall (September through November), and for each time-of-day block set forth in the PJM Manuals, the Office of the Interconnection shall establish Operating Reserve Demand Curves for each Reserve Zone or Reserve Sub-zone as follows:

(i) Each Operating Reserve Demand Curve shall be plotted on a graph on which megawatts of reserve is on the x-axis and price is on the y-axis;

(ii) The Operating Reserve Demand Curve for each Reserve Zone or Reserve Sub-zone shall be plotted by combining (i) a straight horizontal line starting from point (1) on the y-axis to point (2), (ii) a straight vertical line connecting points (2) and (3), and (iv) a curved line from point (3) to the x-axis, where:

(A) Point (1) is the point on the y-axis(price) equal to the Reserve Penalty Factor for the minimum reserve requirement for the subject reserve requirement (i.e., the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement, or the Minimum Synchronized Reserve Requirement);

(B) Point (2) has the y-axis coordinate of point (1) and the x-axis coordinate of the applicable minimum reserve requirement as determined for the Reserve Zone or Reserve Sub-zone in accordance with the PJM Manuals;

(C) Point (3) has the x-axis coordinate of the applicable minimum reserve requirement and the y-axis coordinate resulting from multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring an infinitesimal amount of additional MW of reserves beyond the minimum reserve requirement; and

(D) From point (3) to the x-axis, first, the Office of the Interconnection develops a curve starting at point (3). The shape of the curve will be determined by multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring each additional MW of reserves beyond the minimum reserve requirement until the resulting product falls below \$0.01/MWh at which point the curve will intersect with the x-axis. These probabilities are calculated from an empirical distribution of data from a rolling three-calendar year period of the following supply and demand uncertainties, using a 30-minute time horizon for clearing Primary Reserves and Synchronized Reserves and a 60-minute time horizon for clearing 30-minute Reserves: load forecast error, wind forecast error, solar forecast error, and forced outages of thermal units, and, for the Operating Reserve Demand Curves for 30-minute Reserves only, net interchange forecast error, all as described in the PJM Manuals. The empirical distribution also accounts for the Regulation requirement, expressed in effective megawatts, that PJM has established for each hour within that time-of-day block, by reducing the magnitude of the above uncertainties by the requirement.

The Office of the Interconnection will post each Operating Reserve Demand Curve used to clear reserve markets.

(c) Annual Update of Operating Reserve Demand Curves

On an annual basis, the Office of the Interconnection shall update the determination of the probability of falling below the applicable minimum reserve requirement, including each uncertainty, to account for the most recent calendar year's data, in accordance with the PJM Manuals, and post revised Operating Reserve Demand Curves by April 1. The revised Operating Reserve Demand Curves shall become effective June 1, coincident with the start of the next Delivery Year.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch

algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to [Sections 3.2.3B\(c\) & 3.2.3B\(d\)](#).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to [Operating Agreement, Schedule 1, Section 1.10.3 \(c\)](#) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to [Operating Agreement, Schedule 1, Section 1.10.3 \(c\)](#) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in [Section 3.2.3B\(c\)](#) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to [Section 3.2.3B\(f\)](#).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to [Operating Agreement, Schedule 1, Section 1.10.3 \(c\)](#) hereof), and where the real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit

determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to $\{(AG - LMPDMW) \times (UB - URTLMP)\}$ where:

AG equals the actual output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the lesser of the Final Offer or Committed Offer;

URLTMP equals the real time LMP at the unit's bus; and

where $UB - URTLMP$ shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to [Operating Agreement, Schedule 1, Section 1.10.3 \(c\)](#) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in [Section 3.2.3A](#) regarding provision of [Tier 2](#) Synchronized Reserve. At the end of each

Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) *excluding Direct Charging Energy*) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said

instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the ~~PJM-applicable~~ Synchronized Reserve ~~Requirements~~. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in ~~s~~Section 3.2.3A regarding provision of ~~Tier 2~~ Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's applicable interval cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the applicable interval product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-

contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) *excluding Direct Charging Energy*) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Operating Agreement, Schedule 1, Section 5 ~~of this Schedule~~.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Operating Agreement, Schedule 1, Section 5 ~~of this Schedule~~.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at ~~the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement~~ \$2,000/MWh, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or

suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in Operating Agreement, Schedule 1, S~~sections 3.2.1 through 3.2.6 of this Schedule~~, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.

(b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, S~~ection 14 of the Operating Agreement~~ include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

Attachment B

Revisions to the PJM Operating Agreement (Clean)

Definitions A - B

30-minute Reserve:

“30-minute Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

“30-minute Reserve Requirement” shall mean the demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, as defined by the Operating Reserve Demand Curve for 30-minute Reserve. The requirement can be satisfied by any combination of Synchronized Reserve, Non-Synchronized Reserve or Secondary Reserve resources.

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A and the parallel provisions of Tariff, Attachment K-Appendix, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 and Tariff, Attachment K-Appendix, section 1.9.4.

Act:

“Act” shall mean the Delaware Limited Liability Company Act, Title 6, §§ 18-101 to 18-1109 of the Delaware Code.

Active and Significant Business Interest:

“Active and Significant Business Interest” is a term that shall be used to assess the scope of a Member’s PJM membership and shall be based on a Member’s activity in the PJM RTO and/or Interchange Energy Markets. A Member’s Active and Significant Business Interest shall: 1) be determined relative to the scope of the Member’s PJM membership and activity in the PJM RTO and/or Interchange Energy Markets considering, among other things, the Member’s public statements and/or regulatory filings regarding its PJM activities; and 2) reflect a substantial contributor to the Member’s recent market activity, revenues, costs, investment, and/or earnings when considering the Member and its corporate affiliates’ interests within the PJM footprint.

Affected Member:

“Affected Member” shall mean a Member of PJM which as a result of its participation in PJM’s markets or its membership in PJM provided confidential information to PJM, which confidential information is requested by, or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which controls the other or that are under common control. “Control” shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

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

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

Annual Meeting of the Members:

“Annual Meeting of the Members” shall mean the meeting specified in Operating Agreement, section 8.3.1.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Associate Member:

“Associate Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.7.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Commission:

“Authorized Commission” shall mean (i) a State public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

Authorized Person:

“Authorized Person” shall have the meaning set forth in Operating Agreement, section 18.17.4.

Balancing Congestion Charges:

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Batch Load Economic Load Response Participant Resource:

“Batch Load Economic Load Response Participant Resource” shall mean an Economic Load Response Participant resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for

periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit’s capacity that is designated as a Generation Capacity Resource, or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Board Member:

“Board Member” shall mean a member of the PJM Board.

Definitions C - D

Capacity Resource:

“Capacity Resource” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Storage Resource:

“Capacity Storage Resource” shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM’s markets such as through a Fixed Resource Requirement Capacity Plan.

Catastrophic Force Majeure:

“Catastrophic Force Majeure” shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection’s determination is subject to review by the Commission.

Cold/Warm/Hot Notification Time:

“Cold/Warm/Hot Notification Time” shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, “Cold/Warm/Hot Start-up Time” shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans,

water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

“Cold Weather Alert” shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Committed Offer:

The “Committed Offer shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, or Operating Agreement, Schedule 1, section 6.6 for a particular clock hour for an Operating Day.

Compliance Monitoring and Enforcement Program:

“Compliance Monitoring and Enforcement Program” shall mean the program to be used by the NERC and the Regional Entities to monitor, assess and enforce compliance with the NERC Reliability Standards. As part of a Compliance Monitoring and Enforcement Program, NERC and the Regional Entities may, among other things, conduct investigations, determine fault and assess monetary penalties.

Congestion Price:

“Congestion Price” shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

“Consolidated Transmission Owners Agreement,” “PJM Transmission Owners Agreement” or Transmission Owners Agreement” shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

- (a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;
- (d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and
- (e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Counterparty:

“Counterparty” shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i)

any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the extent that energy serves that Member's own load.

Credit Breach:

"Credit Breach" is the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in Schedule A to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailed Service Provider:

"Curtailed Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Day-ahead Congestion Price:

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the

Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

“Day-ahead Energy Market Injection Congestion Credits” shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

“Day-ahead Energy Market Transmission Congestion Charges” shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

“Day-ahead Energy Market Withdrawal Congestion Charges” shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

“Day-ahead Loss Price” shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

“Day-ahead Prices” shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-Ahead Pseudo-Tie Transaction:

“Day-Ahead Pseudo-Tie Transaction” shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Settlement Interval:

“Day-ahead Settlement Interval” shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

“Day-ahead System Energy Price” shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default Allocation Assessment:

“Default Allocation Assessment” shall mean the assessment determined pursuant to Operating Agreement, section 15.2.2.

Demand Bid:

“Demand Bid” shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

“Demand Bid Limit” shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

“Demand Bid Screening” shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:

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

Designated Entity:

“Designated Entity” shall mean an entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Operating Agreement, Schedule 6, section 1.5.8.

Direct Charging Energy:

“Direct Charging Energy” shall mean the energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

“Direct Load Control” shall mean load reduction that is controlled directly by the Curtailment Service Provider’s market operations center or its agent, in response to PJM instructions.

Dispatch Rate:

“Dispatch Rate” shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dispatched Charging Energy:

“Dispatched Charging Energy” shall mean Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid pursuant to PJM dispatch while providing a service in the PJM markets.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Dynamic Transfer:

“Dynamic Transfer” shall mean a Pseudo-Tie or Dynamic Schedule.

Definitions E - F

Economic-based Enhancement or Expansion:

“Economic-based Enhancement or Expansion” shall mean an enhancement or expansion described in Operating Agreement, Schedule 6, section 1.5.7(b) (i) – (iii) that is designed to relieve transmission constraints that have an economic impact.

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective Date:

“Effective Date” shall mean August 1, 1997, or such later date that FERC permits the Operating Agreement to go into effect.

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common

ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EIDSN, Inc.:

“EIDSN, Inc.” shall mean the nonstock, nonprofit corporation, formerly known as Eastern Interconnection Data Sharing Network, Inc., or any successor thereto, that is operated primarily for the purpose of developing operating tools and the facilitation of the secure, consistent, effective, and efficient sharing of important electric transmission and operational data among reliability coordinators and other relevant parties to help improve electric industry operations and promote the reliable and efficient operation of the bulk electric system in the Eastern Interconnection.

Electric Distributor:

“Electric Distributor” shall mean a Member that: 1) owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

“Emergency” shall mean: (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

Emergency Load Response Program:

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

End-Use Customer:

“End-Use Customer” shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Member Committee classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced

capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Market Opportunity Cost:

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Storage Resource:

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant.

Energy Storage Resource Model Participant:

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-XXX-000.

Equivalent Load:

“Equivalent Load” shall mean the sum of a Market Participant’s net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

External Market Buyer:

“External Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

“External Resource” shall mean a generation resource located outside the metered boundaries of the PJM Region.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Final Offer:

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for an Operating Day.

Finance Committee:

“Finance Committee” shall mean the body formed pursuant to Operating Agreement, section 7.5.1.

Financial Transmission Right:

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Financial Transmission Right Option:

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Flexible Resource:

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall mean individual Transmission Owner FERC-filed planning criteria as described in Operating Agreement, Schedule 6, section 1.2(e) and filed with FERC Form No. 715 and posted on the PJM website.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

Fuel Cost Policy:

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offer(s) for a generation resource.

Definitions I - L

Immediate-need Reliability Project:

“Immediate-need Reliability Project” shall mean a reliability-based transmission enhancement or expansion that the Office of the Interconnection has identified to resolve a need that must be addressed within three years or less from the year the Office of the Interconnection identified the existing or projected limitations on the Transmission System that gave rise to the need for such enhancement or expansion pursuant to the study process described in Operating Agreement, Schedule 6, section 1.5.3.

Inadvertent Interchange:

“Inadvertent Interchange” shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

Increment Offer:

“Increment Offer” shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.

Incremental Energy Offer:

“Incremental Energy Offer” shall mean offer segments comprised of a pairing of price (in dollars per MWh) and megawatt quantities, which must be a non-decreasing function and taken together produce all of the energy segments above a resource’s Economic Minimum. No-load Costs are not included in the Incremental Energy Offer.

Incremental Multi-Driver Project:

“Incremental Multi-Driver Project” shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Information Request:

“Information Request” shall mean a written request, in accordance with the terms of the Operating Agreement for disclosure of confidential information pursuant to Operating Agreement, section 18.17.4.

Interface Pricing Point:

“Interface Pricing Point” shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.6A.

Internal Market Buyer:

“Internal Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service

Interregional Transmission Project:

“Interregional Transmission Project” shall mean transmission facilities that would be located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to regional transmission needs.

LLC:

“LLC” shall mean PJM Interconnection, L.L.C., a Delaware limited liability company.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Reduction Event:

“Load Reduction Event” shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

“Load Serving Charging Energy” shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity:

“Load Serving Entity” or “LSE” shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of

transmission and ancillary services.

Local Plan:

“Local Plan” shall include Supplemental Projects as identified by the Transmission Owners within their zone and Subregional RTEP projects developed to comply with all applicable reliability criteria, including Transmission Owners’ planning criteria or based on market efficiency analysis and in consideration of Public Policy Requirements.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

Locational Marginal Price:

“Locational Marginal Price” or “LMP” shall mean the market clearing marginal price for energy at the location the energy is delivered or received, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Long-lead Project:

“Long-lead Project” shall mean a transmission enhancement or expansion with an in-service date more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect

on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Definitions M - N

M2M Flowgate:

“M2M Flowgate” shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Market Buyer:

“Market Buyer” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and that is otherwise able to make purchases in the PJM Interchange Energy Market.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” shall mean the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM.

Market Operations Center:

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

“Market Revenue Neutrality Offset” shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller:

“Market Seller” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and that is otherwise able to make sales in the PJM Interchange Energy Market.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Generation Emergency:

“Maximum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical

power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.6 and that (i) is a member of the LLC immediately prior to the Effective Date, or (ii) has executed an Additional Member Agreement in the form set forth in Operating Agreement, Schedule 4.

Members Committee:

“Members Committee” shall mean the committee specified in Operating Agreement, section 8, composed of representatives of all the Members.

Minimum 30-minute Reserve Requirement:

“Minimum 30-minute Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as 30-minute Reserve, inclusive of any increase to account for additional reserves scheduled to address operational uncertainty. The Minimum 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals

and establishes the first segment on the Operating Reserve Demand Curve for 30-minute Reserve.

Minimum Generation Emergency:

“Minimum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker opening and after the unit’s generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, “Minimum Down Time” shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Primary Reserve Requirement:

“Minimum Primary Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve, inclusive of any increase to account for additional reserves scheduled to address operational uncertainty. The Minimum Primary Reserve Requirement is calculated in accordance with the PJM Manuals, and establishes the first segment on the Operating Reserve Demand Curve for Primary Reserve.

Minimum Run Time:

For all generating units that are not combined cycle units, “Minimum Run Time” shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, “Minimum Run Time” shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM’s State Estimator.

Minimum Synchronized Reserve Requirement:

“Minimum Synchronized Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, inclusive of any increase to account for additional reserves scheduled to address operational uncertainty. The Minimum Synchronized Reserve Requirement is calculated in accordance with the PJM

Manuals, and establishes the first segment on the Operating Reserve Demand Curve for Synchronized Reserve.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Multi-Driver Project:

“Multi-Driver Project” shall mean a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation, or any successor thereto.

NERC Functional Model:

“NERC Functional Model” shall be the set of functions that must be performed to ensure the reliability of the electric bulk power system. The NERC Reliability Standards establish the requirements of the responsible entities that perform the functions defined in the Functional Model.

NERC Interchange Distribution Calculator:

“NERC Interchange Distribution Calculator” shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

NERC Reliability Standards:

“NERC Reliability Standards” shall mean those standards that have been developed by NERC and approved by FERC to ensure the reliability of the electric bulk power system.

NERC Rules of Procedure: “NERC Rules of Procedure” shall be the rules and procedures developed by NERC and approved by the FERC. These rules include the process by which a responsible entity, who is to perform a set of functions to ensure the reliability of the electric bulk power system, must register as the Registered Entity.

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads

resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Network Resource:

“Network Resource” shall have the meaning specified in the PJM Tariff.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

Non-Disclosure Agreement:

“Non-Disclosure Agreement” shall mean an agreement between an Authorized Person and the Office of the Interconnection, pursuant to Operating Agreement, section, the form of which is appended to this Agreement as Operating Agreement, Schedule 10, wherein the Authorized Person is given access to otherwise restricted confidential information, for the benefit of their respective Authorized Commission.

Non-Dispatched Charging Energy:

“Non-Dispatched Charging Energy” shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Nonincumbent Developer:

“Nonincumbent Developer” shall mean: (1) a transmission developer that does not have an existing Zone in the PJM Region as set forth in Tariff, Attachment J; or (2) a Transmission

Owner that proposes a transmission project outside of its existing Zone in the PJM Region as set forth in Tariff, Attachment J.

Non-Regulatory Opportunity Cost:

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, 1.5A.6.

Normal Maximum Generation:

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

Definitions O - P

Offer Data:

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

Office of the Interconnection:

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

Office of the Interconnection Control Center:

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

On-Site Generators:

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

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

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

Operating Day:

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

Operating Margin:

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

Operating Margin Customer:

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

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Operating Reserve Demand Curve:

“Operating Reserve Demand Curve” shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that can be used to meet a given reserve requirement and the value placed on maintaining that megawatt level of reserve, expressed in \$/MWh.

Operator-initiated Commitment:

“Operator-initiated Commitment” shall mean a commitment after the Day-ahead Energy Market and Day-ahead Scheduling Reserves Market, whether manual or automated, for a reason other than minimizing the total production costs of serving load.

Original PJM Agreement:

“Original PJM Agreement” shall mean that certain agreement between certain of the Members, originally dated September 26, 1956, and as amended and supplemented up to and including December 31, 1996, relating to the coordinated operation of their electric supply systems and the interchange of electric capacity and energy among their systems.

Other Supplier:

“Other Supplier” shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, financial transmission rights or other services available under PJM’s governing documents in or through the Interconnection or has a good faith intent to do so, and; (ii) does not qualify for the Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer sectors.

PJM Board:

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

PJM Control Area:

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

PJM Dispute Resolution Procedures:

“PJM Dispute Resolution Procedures” shall mean the procedures for the resolution of disputes set forth in Operating Agreement, Schedule 5.

PJM Governing Agreements:

“PJM Governing Agreements” shall mean the PJM Open Access Transmission Tariff, the Operating Agreement, the Consolidated Transmission Owners Agreement, the Reliability Assurance Agreement, or any other applicable agreement approved by the FERC and intended to govern the relationship by and among PJM and any of its Members.

PJM Interchange:

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

PJM Interchange Energy Market:

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

PJM Interchange Export:

“PJM Interchange Export” shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load is exceeded by the sum of the interval outputs of

its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller.

PJM Interchange Import:

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

PJM Manuals:

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

PJM Mid-Atlantic Region:

“PJM Mid-Atlantic Region” shall mean the aggregate of the Transmission Facilities of Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC, PECO Energy Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric and Gas Company, and Rockland Electric Company.

PJM Region:

“PJM Region” shall mean the aggregate of the Zones within PJM as set forth in Tariff, Attachment J.

PJMSettlement:

“PJMSettlement” or “PJM Settlement, Inc.” shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operating Agreement, section 3.3.

PJM South Region:

“PJM South Region” shall mean the Transmission Facilities of Virginia Electric and Power Company.

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

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

PJM West Region:

“PJM West Region” shall mean the Zones of Allegheny Power; Commonwealth Edison Company (including Commonwealth Edison Co. of Indiana); AEP East Affiliate Companies; The Dayton Power and Light Company; the Duquesne Light Company; American Transmission Systems, Incorporated; Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc. and East Kentucky Power Cooperative, Inc.

Planning Period:

“Planning Period” shall *have the meaning specified in the Reliability Assurance Agreement.*

Planning Period Balance:

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

Planning Period Quarter:

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

Point-to-Point Transmission Service:

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

PRD Curve:

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

PRD Provider:

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

PRD Reservation Price:

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

PRD Substation:

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

Pre-Emergency Load Response Program:

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

President:

“President” shall have the meaning specified in Operating Agreement, section 9.2.

Price Responsive Demand:

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

Primary Reserve:

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

Primary Reserve Alert:

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

Primary Reserve Requirement:

“Primary Reserve Requirement” shall mean the demand for Primary Reserves in a Reserve Zone or Reserve Sub-zone, as defined by the Operating Reserve Demand Curve for Primary Reserve. The requirement can be satisfied by any combination of Synchronized Reserve or Non-Synchronized Reserve resources.

Prohibited Securities:

“Prohibited Securities” shall mean the Securities of a Member, Eligible Customer, or Nonincumbent Developer, or their Affiliates, if:

(1) the primary business purpose of the Member or Eligible Customer, or their Affiliates, is to buy, sell or schedule energy, power, capacity, ancillary services or transmission services as indicated by an industry code within the “Electric Power Generation, Transmission, and

Distribution” industry group under the North American Industry Classification System (“NAICS”) or otherwise determined by the Office of the Interconnection;

(2) the Nonincumbent Developer has been pre-qualified as eligible to be a Designated Entity pursuant to Operating Agreement, Schedule 6;

(3) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during its most recently completed fiscal year is equal to or greater than 0.5% of its gross revenues for the same time period; or

(4) the total (gross) financial settlements regarding the use of transmission capacity of the Transmission System and/or transactions in the centralized markets that the Office of the Interconnection administers under the Tariff and the Operating Agreement for all Members or Eligible Customers affiliated with the publicly traded company during the prior calendar year is equal to or greater than 3% of the total transactions for which PJM Settlement is a Counterparty pursuant to Operating Agreement, section 3.3 for the same time period.

The Office of the Interconnection shall compile and maintain a list of the Prohibited Securities publicly traded and post this list for all employees and distribute the list to the Board Members.

Proportional Multi-Driver Project:

“Proportional Multi-Driver Project” shall mean a Multi-Driver Project that is planned as described in Operating Agreement, Schedule 6, section 1.5.10(h).

Pseudo-Tie:

“Pseudo-Tie shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

Public Policy Objectives:

“Public Policy Objectives” shall refer to Public Policy Requirements, as well as public policy initiatives of state or federal entities that have not been codified into law or regulation but which nonetheless may have important impacts on long term planning considerations.

Public Policy Requirements:

“Public Policy Requirements” shall refer to policies pursued by: (a) state or federal entities, where such policies are reflected in duly enacted statutes or regulations, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations; and (b) local governmental entities such as a municipal or county government,

where such policies are reflected in duly enacted laws or regulations passed by the local governmental entity.

Definitions Q - R

Ramping Capability:

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

Real-time Congestion Price:

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

Real-time Loss Price:

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

Real-time Offer:

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

Real-time Prices:

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

Real-time Energy Market:

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

Real-time Settlement Interval:

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

Real-time System Energy Price:

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

Regional Entity:

“Regional Entity” shall mean an organization that NERC has delegated the authority to propose and enforce reliability standards pursuant to the Federal Power Act.

Regional RTEP Project:

“Regional RTEP Project” shall mean a transmission expansion or enhancement rated at 230 kV or above which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Registered Entity:

“Registered Entity” shall mean the entity registered under the NERC Functional Model and NERC Rules of Procedures for the purpose of compliance with NERC Reliability Standards and responsible for carrying out the tasks within a NERC function without regard to whether a task or tasks are performed by another entity pursuant to the terms of the PJM Governing Agreements.

Regulation:

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

Regulation Zone:

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

Related Parties:

“Related Parties” shall mean, solely for purposes of the governance provisions of the Operating Agreement: (i) any generation and transmission cooperative and one of its distribution cooperative members; and (ii) any joint municipal agency and one of its members. For purposes of the Operating Agreement, representatives of state or federal government agencies shall not be deemed Related Parties with respect to each other, and a public body's regulatory authority, if any, over a Member shall not be deemed to make it a Related Party with respect to that Member.

Relevant Electric Retail Regulatory Authority:

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

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

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

Reserve Penalty Factor:

“Reserve Penalty Factor” shall mean the maximum production cost, in \$/MWh, willing to be incurred to meet the Minimum Primary Reserve Requirement, Minimum Synchronized Reserve Requirement, or Minimum 30-minute Reserve Requirement for a given Reserve Zone or Reserve Sub-zone, as specified by the applicable Operating Reserve Demand Curve.

Reserve Sub-zone:

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

Reserve Zone:

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

Residual Auction Revenue Rights:

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

Residual Metered Load:

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

Revenue Data for Settlements:

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

Definitions S – T

Secondary Reserve:

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

Sector Votes:

“Sector Votes” shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Operating Agreement, section 8.4.

Securities:

“Securities” shall mean negotiable or non-negotiable investment or financing instruments that can be sold and bought. Securities include bonds, stocks, debentures, notes and options.

Segment:

“Segment” shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(e).

Senior Standing Committees:

“Senior Standing Committees” shall mean the Members Committee, and the Markets, and Reliability Committee, as established in Operating Agreement, section 8.1 and Operating Agreement, section 8.6.

SERC:

“SERC” or “Southeastern Electric Reliability Council” shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

Short-term Project:

“Short-term Project” shall mean a transmission enhancement or expansion with an in-service date of more than three years but no more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Special Member:

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

Spot Market Backup:

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

Spot Market Energy:

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

Standing Committees:

“Standing Committees” shall mean the Members Committee, the committees established and maintained under Operating Agreement, section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

Start-Up Costs:

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

State:

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

State Certification:

“State Certification” shall mean the Certification of an Authorized Commission, pursuant to Operating Agreement, section 18, the form of which is appended to the Operating Agreement as Operating Agreement, Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Estimator:

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

Station Power:

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

Sub-meter:

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

Subregional RTEP Project:

“Subregional RTEP Project” shall mean a transmission expansion or enhancement rated below 230 kV which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Supplemental Project:

“Supplemental Project” shall mean a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). Any system upgrades required to maintain the reliability of the system that are driven by a

Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

Synchronized Reserve:

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

Synchronized Reserve Event:

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

Synchronized Reserve Requirement:

“Synchronized Reserve Requirement” shall mean the demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, as defined by the Operating Reserve Demand Curve for Synchronized Reserve. The requirement can only be satisfied by Synchronized Reserve resources.

System:

“System” shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

System Energy Price:

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

Target Allocation:

“Target Allocation” shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3 or the allocation of Auction Revenue Rights Credits as set

forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Party Request:

“Third Party Request” shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or the Market Monitoring Unit. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

Tie Line:

“Tie Line” shall have the same meaning provided in the Open Access Transmission Tariff.

Total Lost Opportunity Cost Offer:

“Total Lost Opportunity Cost Offer” shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated costbased Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Operating Reserve Offer:

“Total Operating Reserve Offer” shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses, which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

“Transmission Congestion Credit” shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Customer:

“Transmission Customer” shall have the meaning set forth in the PJM Tariff.

Transmission Facilities:

“Transmission Facilities” shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Forced Outage:

“Transmission Forced Outage” shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Loading Relief:

“Transmission Loading Relief” shall mean NERC’s procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loading Relief Customer:

“Transmission Loading Relief Customer” shall mean an entity that, in accordance with Operating Agreement, Schedule 1, section 1.10.6A and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

Transmission Loss Charge:

“Transmission Loss Charge” shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall mean an upgrade to a Transmission Owner’s own transmission facilities, which is an improvement to, addition to, or replacement of a part of, an existing facility and is not an entirely new transmission facility.

Transmission Planned Outage:

“Transmission Planned Outage” shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix, or the PJM Manuals.

Turn Down Ratio:

“Turn Down Ratio” shall mean the ratio of a generating unit’s economic maximum megawatts to its economic minimum megawatts.

1.5A Economic Load Response Participant.

As used in this section 1.5A, the term “end-use customer” refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number.

1.5A.1 Qualification.

A Member or Special Member that is an end-use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis (or for non-interval metered residential Direct Load Control customers, as metered on a statistical sample of electric distribution company accounts utilizing current data, as described in the PJM Manuals) or has an On-Site Generator that enables demand reduction may become an Economic Load Response Participant by complying with the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with this section 1.5A including, but not limited to, section 1.5A.3 below. A Member or Special Member may aggregate multiple individual end-use customer sites to qualify as an Economic Load Response Participant, subject to the requirements of section 1.5A.10 below.

1.5A.2 Special Member.

Entities that are not Members and desire to participate solely in the Real-time Energy Market by reducing demand may become a Special Member by paying an annual membership fee of \$500 plus 10% of each payment owed by PJM Settlement for a Load Reduction Event not to exceed \$5,000 in a calendar year. For entities that become Special Members pursuant to this section, the following obligations are waived: (i) the \$1,500 membership application fee set forth in Operating Agreement, Schedule 1, section 1.4.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.4.3; (ii) liability under Operating Agreement, section 15.2 for Member defaults; (iii) thirty days notice for waiting period; and (iv) the requirement for 24/7 control center coverage. In addition, such Members shall not have voting privileges in committees or sector designations, and shall not be permitted to form user groups. On January 1 of a calendar year, a Special Member under this section, at its sole election, may become a Member rather than a Special Member subject to all rules governing being a Member, including regular application and membership fee requirements.

1.5A.3 Registration.

1. Prior to participating in the PJM Interchange Energy Market or Ancillary Services Market, Economic Load Response Participants must complete either the Economic Load Response or Economic Load Response Regulation Only Registration Form posted on the Office of the Interconnection’s website and submit such form to the Office of the Interconnection for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Notwithstanding the below sub-provisions, Economic Load Response Regulation Only registrations and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market will not require the identification of the

relevant Load Serving Entity, nor will such relevant Load Serving Entity be notified of such registration or requested to verify such registration. All other below sub-provisions apply equally to Economic Load Response Regulation Only registrations, and Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, as well as Economic Load Response registrations.

a. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is subject to another contractual obligation or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. A relevant electric distribution company or Load Serving Entity which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation in PJM's Economic Load Response program shall provide to PJM, within the referenced ten Business Day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Economic Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets the requirements of this section 1.5A.

b. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

- i. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the relevant electric distribution company or Load Serving Entity, as determined based upon the type of registration submitted (i.e., either an Economic Load Response registration, Economic Load Response residential customer registrations not participating in the Day-ahead Energy Market, or an Economic Load Response Regulation Only registration), of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is permitted to participate in PJM's Economic Load Response Program. The relevant electric distribution company or Load Serving Entity shall have ten Business Days to respond. If the relevant electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then the electric distribution company or the Load Serving Entity must provide to the Office of the Interconnection within the referenced ten Business Day review period evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.
- ii. In the absence of a response from the relevant electric distribution company or Load Serving Entity within the referenced ten Business Day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with this section 1.5A, including this subsection 1.5A.3, the Economic Load Response Participant may submit a new registration for consideration if a prior registration has been rejected pursuant to this subsection.

2. In the event that the end-use customer is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end-use customer or appropriate Curtailment Service Provider, or relevant electric distribution company and/or Load Serving Entity that the Economic Load Response Participant has or has not met the requirements of this section 1.5A. An end-use

customer that desires not to be simultaneously registered to reduce demand under the Emergency Load Response and Pre-Emergency Load Response Programs and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

1.5A.3.01 Economic Load Response Registrations in Effect as of August 28, 2009

1. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. Effective as of the later of either August 28, 2009 (the effective date of Wholesale Competition in Regions with Organized Electric Markets, Order 719-A, 128 FERC ¶ 61,059 (2009) (“Order 719-A”)) or the effective date of a Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer’s participation in PJM’s Economic Load Response Program, the existing Economic Load Response Participant’s registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated upon an electric distribution company or Load Serving Entity submitting to the Office of the Interconnection either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer’s participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority’s legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer’s participation.

i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

2. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. Effective as of August 28, 2009 (the effective date of Order 719-A), an existing Economic Load Response Participant's registration submitted to the Office of the Interconnection prior to August 28, 2009, will be deemed to be terminated unless an electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program and provides evidence to the Office of the Interconnection documenting that the permission or conditional permission is pursuant to the laws or regulations of the Relevant Electric Retail Regulatory Authority. If the electric distribution company or Load Serving Entity verifies that the existing registration is permitted or conditionally permitted (which condition the electric

distribution company or Load Serving Entity asserts has been satisfied) to participate in the Economic Load Response Program, then, within ten Business Days of verifying such permission or conditional permission, the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program. Evidence from the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the Economic Load Response Participant to participate in the Economic Load Response Program shall be in the form of either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

- i. For registrations terminated pursuant to this section, all Economic Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM Settlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. All registrations submitted to the Office of the Interconnection on or after August 28, 2009, including requests to extend existing registrations, will be processed by the Office of the Interconnection in accordance with the provisions of this section 1.5A, including this subsection 1.5A.3.

1.5A.3. 02 Economic Load Response Regulation Only Registrations.

An Economic Load Response Regulation Only registration allows end-use customer participation in the Regulation market only, and may be submitted by a Curtailment Service Provider that is different than the Curtailment Service Provider that submits an Emergency Load Response Program registration, Pre-Emergency Load Response Program registration or Economic Load Response registration for the same end-use customer. An end-use customer that is registered as Economic Load Response Regulation Only shall not be permitted to register and/or participate in any other Ancillary Service markets at the same time, but may have a second, simultaneously existing Economic Load Response registration to participate in the PJM Interchange Energy Market as set forth in the PJM Manuals.

1.5A.4 Metering and Electronic Dispatch Signal.

a) The Curtailment Service Provider is responsible for ensuring that end-use customers have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. For non-interval metered residential customers not participating in the pilot program under section 1.5A.7 below, the Curtailment Service Provider must ensure that a representative sample of residential customers has metering equipment that provides integrated

hourly kWh values on an electric distribution company account basis, as set forth in the PJM Manuals. The metering equipment shall either meet the electric distribution company requirements for accuracy, or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. End-use customer reductions in demand must be metered by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), or by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to Operating Agreement, Schedule 1, section 3.3A and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, electric distribution company and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, hourly data reflecting meter readings for each day during which the load reduction occurred and all associated days to determine the reduction must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

Curtailment Service Providers that have end-use customers that will participate in the Regulation market may be permitted to use Sub-metered load data instead of load data at the electric distribution company account number level for Regulation measurement and verification as set forth in the PJM Manuals and subject to the following:

- a. Curtailment Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.
- b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailment Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process.
- c. The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailment Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.
- d. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailment Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the

matter to the Market Monitoring Unit and/or the Federal Energy Regulatory Commission Office of Enforcement.

b) Curtailment Service Providers shall be responsible for maintaining, or ensuring that Economic Load Response Participants maintain, the capability to receive and act upon an electronic dispatch signal from the Office of the Interconnection in accordance with any standards and specifications contained in the PJM Manuals.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Variable-Load Customers.

The loads of an Economic Load Response Participant shall be categorized as variable or non-variable at the time the load is registered, based on hourly load data for the most recent 60 days provided by the Market Participant in the registration process; provided, however, that any alternative means of making such determination when 60 days of data is not available shall be subject to review and approval by the Office of the Interconnection and provided further that 60 days of hourly load data shall not be required on an individual customer basis for non-interval metered residential or Small Commercial Customers that provide Economic Load Response through a direct load control program under which an electric distribution company, Load Serving Entity, or CSP has direct control over such customer's load, without reliance upon any action by such customer to reduce load. Non-Variable Loads shall be those for which the Customer Baseline Load calculation and adjustment methods prescribed by Operating Agreement, Schedule 1, section 3.3A.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.2 and Operating Agreement, Schedule 1, section 3.3A.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.3 result in a relative root mean square hourly error of twenty percent or less compared to the actual hourly loads based on the hourly load data provided in the registration process and using statistical methods prescribed in the PJM Manuals. All other loads shall be Variable Loads.

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The Curtailment Service Provider or PJM must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection

(“Pilot Period”). Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in the Emergency Load Response Program, Pre-Emergency Load Response Program and the PJM Interchange Energy Market or Synchronized Reserve market. With the sole exception of the requirement for hourly metering as set forth in section 1.5A.4 above, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market, including, without limitation, the Net Benefits Test and the requirement for dispatch by the Office of the Interconnection. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

1.5A.8 Batch Load Economic Load Response Participant Resource Provision of Synchronized Reserve or Secondary Reserve.

(a) A Batch Load Economic Load Response Participant Resource may provide Synchronized Reserve or Secondary Reserves in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Economic Load Response Participant Resource , or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of “Batch Load Economic Load Response Participant Resource” pursuant to Operating Agreement, Schedule 1, section 1.3.1A.001 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.3.1A.001. This requirement is a one-time pre-qualification requirement for a Batch Load Economic Load Response Participant Resource .

(b) Batch Load Economic Load Response Participant Resources may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour, or up to 20 percent of the total system-wide Secondary Reserves requirement in any hour; provided, however, that in the event the Office of the Interconnection determines in its sole discretion that satisfying 20 percent of either such requirement from Batch Load Economic Load Response Participant Resources is causing or may cause a reliability degradation, the Office of the Interconnection may reduce the percentage of either such requirement that may be satisfied by Batch Load Economic Load Response Participant Resources in any hour to as low as 10 percent. This reduction will be effective seven days after the posting of the reduction on the PJM website. Notwithstanding anything to the contrary in this Agreement, as soon as practicable, the Office of the Interconnection unilaterally shall make a filing under section 205 of the Federal Power Act to revise the rules for Batch Load Economic Load Response Participant Resources so as to continue such reduction. The reduction shall remain in effect until the Commission acts upon the Office of the Interconnection’s filing and thereafter if approved or accepted by the Commission.

(c) A Batch Load Economic Load Response Participant Resource that is consuming energy at the start of a Synchronized Reserve Event, or, if committed to provide Secondary

Reserve, at the time of a dispatch instruction from the Office of the Interconnection to reduce load, shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event, or to such instruction to reduce load, by reducing load as quickly as it is capable and by keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following the reduction, or, in the case of Secondary Reserve, until a dispatch instruction that load reductions are no longer required. A Batch Load Economic Load Response Participant Resource that has reduced its consumption of energy for its production processes to minimal or zero megawatts before the start of a Synchronized Reserve Event (or, in the case of Secondary Reserve, before a dispatch instruction to reduce load) shall respond to the Office of the Interconnection's calling of a Synchronized Reserve Event (or such instruction to reduce load) by reducing any load that is present at the time the Synchronized Reserve Event is called (or at the time of such instruction to reduce load) as quickly as it is capable, delaying the restart of its production processes, and keeping its consumption at or near zero megawatts for the entire length of the Synchronized Reserve Event following any such reduction (or, in the case of Secondary Reserve, until a dispatch instruction that load reductions are no longer required). Failure to respond as described in this section shall be considered non-compliance with the Office of the Interconnection's dispatch instruction associated with a Synchronized Reserve Event, or as applicable, associated with an instruction to a resource committed to provide Secondary Reserve to reduce load.

1.5A.9 Day-ahead and Real-time Energy Market Participation.

Economic Load Response Participants shall be compensated under Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6 only if they participate in the Day-ahead or Real-time Energy Markets as a dispatchable resource.

1.5A.10 Aggregation for Economic Load Response Registrations.

The purpose for aggregation is to allow the participation of End-Use Customers in the Energy Market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 0.1 megawatt of demand response in the Secondary Reserve, Synchronized Reserve or Regulation markets when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All End-Use Customers in an aggregation shall be specifically identified;
- ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation. Residential customers that are part of an aggregate that does not participate in the Day-Ahead Energy Market do not need to share the same Load Serving Entity. If the aggregation will provide Synchronized Reserves, all customers in the aggregation must also be part of the same Synchronized Reserve sub-zone;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. A single CBL for the aggregation shall be used to determine settlements pursuant to Operating Agreement, Schedule 1, section 3.3A.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.5 and Operating Agreement, Schedule 1, section 3.3A.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.6;

v. If the aggregation will only provide energy to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve. If the aggregation will provide an Ancillary Service to the market then only one End-Use Customer within the aggregation shall have the ability to reduce more than 0.099 megawatt of load unless the Curtailment Service Provider, Load Serving Entity and PJM approve;

vi. Each End-Use Customer site must meet the requirements for market participation by an Economic Load Response Participant resource except for the 0.1 megawatt minimum load reduction requirement for energy or the 0.1 megawatt minimum load reduction requirement for Ancillary Services; and

vii. An End-Use Customer's participation in the Energy and Ancillary Services markets shall be administered under one economic registration.

1.5A.10.01 Aggregation for Economic Load Response Regulation Only Registrations

The purpose for aggregation is to allow the participation of end-use customers in the Regulation market that can provide less than 0.1 megawatt of demand response when they currently have no alternative opportunity to participate on an individual basis. Aggregations pursuant to section 1.5A.1 above shall be subject to the following requirements:

- i. All end-use customers in an aggregation shall be specifically identified;
- ii. All end-use customers in the aggregation must be served by the same electric distribution company and must also be part of the same Transmission Zone; and
- iii. Each end-use customer site must meet the requirements for market participation by an Economic Load Response Participant resource except for the 0.1 megawatt minimum load reduction requirement for Regulation service.

1.5A.11 Reporting

(a) PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

(b) As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.5A.3 above, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Economic Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers *and Energy Storage Resources* shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.2B Energy Storage Resources.

Energy that an Energy Storage Resource purchases from the PJM Interchange Energy Market must be Direct Charging Energy. Energy Storage Resources shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and each Applicable Regional Entity, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, Economic Load Response Participant resources, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner. Market Participants that request additional information or communications system access or connections beyond those which are required by the Office of the Interconnection for reliability in the operation of the LLC or the Office of the Interconnection, including but not limited to PJMnet or Internet SCADA connections, shall be solely responsible for the cost of such additional access and connections and for purchasing, leasing, installing and maintaining any associated facilities and equipment, which shall remain the property of the Market Participant.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with

Operating Agreement, section 14, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Tariff, section 36.1.1, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement, and as may be further described in the PJM Manuals, for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Economic Load Response Participant resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by

Market Sellers, continuing until sufficient generation resources and/or Economic Load Response Participant resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Economic Load Response Participant resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the applicable interval Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in the applicable interval, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues from there shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Operating Agreement, Schedule 1, section 3. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

- (i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its InSchedule and ExSchedule tools.
- (ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.
- (iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with

the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

- (iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.
- (v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new InSchedule or ExSchedule reporting by the Market Participant and (ii) terminate all of the Market Participant's InSchedules and ExSchedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the InSchedules and ExSchedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.
- (vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not Dynamic Transfers pursuant to Operating Agreement, Schedule 1, section 1.12 and that

are curtailed or interrupted for any reason (except for curtailments or interruptions through Load Management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

- (i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any Real-time Settlement Interval during the month. For each Real-time Settlement Interval when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that Real-time Settlement Interval hour for all of the energy delivered. Conversely, for each Real-time Settlement Interval when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that Real-time Settlement Interval for all of the energy consumed.
- (ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of

energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Tariff, Part II and shall be charged the hourly rate under Tariff, Schedule 8 for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Tariff, Schedule 1; Tariff, Schedule 1A; Tariff, Schedule 2; Tariff, Schedule 3; Tariff, Schedule 4; Tariff, Schedule 5; Tariff, Schedule 6; Tariff, Schedule 9; and Tariff, Schedule 10 shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

- (iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load

within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This subsection shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection, and for additional services they request from the LLC, PJMSettlement or the Office of the Interconnection that are not required for the operation of the LLC or the Office of the Interconnection, in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Entity reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the

Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Economic Load Response Participant resources subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Economic Load Response Participant resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Economic Load Response Participant resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

- (c) The Regulation range of a generation unit or Economic Load Response Participant resources shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.
- (d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.
- (e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator. Market Sellers must specify a ramping rate in the Offer Data that is an accurate representation of the resource's capabilities given the confines of the PJM software.

1.7.19A Synchronized Reserve.

- (a) Synchronized Reserve can be supplied from generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region. A resource is not eligible to provide Synchronized Reserve if its entire output has been designated as emergency energy. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.
- (b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary Reserve Requirement and Synchronized Reserve Requirement for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to a specific geographic area of the PJM Region where reserves are required.
- (c) The Synchronized Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource or Economic Load Response Participant resource within a continuous 10-minute period.

1.7.19A.01 Non-Synchronized Reserve.

(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 are not available to provide energy, are not eligible to provide Non-Synchronized Reserve. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve Requirement for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Non-Synchronized Reserve capability of a generation resource shall be the increase in energy output achievable by the generation resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

1.7.19A.02 Secondary Reserve.

(a) Secondary Reserve can be supplied from synchronized and non-synchronized generation resources and/or Economic Load Response Participant resources located within the metered boundaries of the PJM Region, as specified in the PJM Manuals. A resource is not eligible to provide Secondary Reserve if its entire output has been designated as emergency energy or if the resource is not available to provide energy. Generating Market Buyers and Market Sellers offering Secondary Reserve shall comply with applicable standards and requirements for Secondary Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and the PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone, as applicable, an amount of Secondary Reserve such that the sum of the Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve meets the respective 30-minute Reserve Requirement for each such Reserve Zone and Reserve Sub-zone, as applicable, and as specified in the PJM Manuals. In accordance with the PJM Manuals, the Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the 30-minute Reserve Requirement in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Secondary Reserve capability of a generation resource and Economic Load Response Participant resource shall be the increase in energy output or load reduction achievable by the generation resource and Economic Load Response Participant resource within a continuous 30-minute period, minus the increase in energy output or load reduction achievable within a continuous 10-minute period.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, Non-Synchronized Reserve market, and Secondary Reserve market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its Markets Gateway tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party

under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Secondary Reserve used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new Markets Gateway reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of Markets Gateway schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported Markets Gateway schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve from PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve, or Secondary Reserve to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable, and as may be further described in the PJM Manuals.

(b) Market Sellers selling from generation resources and/or Economic Load Response Participant resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Economic Load Response Participant resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Economic Load Response Participant resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of

the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Economic Load Response Participant resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Economic Load Response Participant resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

(h) Market Participants engaging in Coordinated External Transactions shall provide to the Office of the Interconnection the information required to be specified in a CTS Interface Bid, in

accordance with the procedures of Tariff, Attachment K-Appendix, section 1.13 and the parallel provisions of Operating Agreement, Schedule 1, section 1.13.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) (i) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(ii) In the Real-time Energy Market, Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to pay Transmission Congestion Charges and Transmission Loss Charges for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly

energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Operating Agreement, Schedule 1, section 1.13. Scheduling shall be conducted as specified in section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

1.10.1A Day-ahead and Real-time Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection:
(i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed \$2,000/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to \$2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

- i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;
- ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Operating Agreement, Schedule 1, section 1.12; and
- iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source

and sink prices that a participant may specify shall be limited to +/- \$50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c-2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to \$2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

- i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This

includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

- ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.
- iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.
- iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d), and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

- i) Shall specify the Generation Capacity Resource or Economic Load Response Participant resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;
- ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
- iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; (12) emergency maximum MW; (13) Synchronized Reserve maximum

MW; (14) Secondary Reserve maximum MW; and (15) condense to generation time constraints, and may specify offer parameters for Economic Load Response Participant resource for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

- iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;
- v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;
- vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;
- vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;
- viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above \$1,000/megawatt-hour and less than or equal to \$2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than \$2,000/megawatt-hour, then its market-based offer must be less than or equal to \$2,000/megawatt-hour; and
- ix) Shall not exceed a demand reduction offer price of \$1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above \$1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than \$2,000/megawatt-hour; and

- x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:
 - a) a 30 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, \$1,849/megawatt-hour;
 - b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, \$1,425/megawatt-hour; and
 - c) an approved 120 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provisions of RAA, Schedule 6, \$1,100/megawatt-hour; and
- xi) Shall not exceed an energy offer price of \$0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed \$100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

- i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;
- ii. The cost increase (in \$/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and

- iii. An adder of up to \$12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) (i) Offers to Supply Synchronized and Non-Synchronized Reserves By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (A) are capable of providing Synchronized Reserve or Non-Synchronized Reserve, as specified in the PJM Manuals, (B) are located within the metered boundaries of the PJM Region, and (C) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve or Non-Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve and Non-Synchronized Reserve, as applicable.

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in \$/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the

probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of implementation of this rule the expected value of the penalty shall be \$0.02/MWh, and for the period from the second month after implementation through the second January 1 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

(4) All Non-Synchronized Reserve offers shall be for \$0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) of this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized Reserve capability as part of their offer into the Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B)

Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum; and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(iii) Determination of Available Non-Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available Non-Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Such hydroelectric generation resources or Energy Storage Resources may submit offers for their available Non-Synchronized Reserve capability as part of their offer into the Non-Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Non-Synchronized Reserve offer which specifies the MW of available Non-Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An off-line generation resource's available Non-Synchronized Reserve capability shall be determined in accordance with the PJM Manuals and based on the following offer parameters submitted as part of the resource's energy offer: (A) startup time; (B) notification time; (C) ramp rate; (D) Economic Minimum; and (E) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of

the Interconnection that the resource has an operating configuration that prevents it from reliably providing Non-Synchronized Reserves above its Synchronized Reserve maximum MW.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

(1) Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve may submit offers to supply Synchronized Reserve from such resources, where such offers shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, as determined in accordance with section 1.10.1A(j)(i)(3) above. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts; (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, shutdown costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of an Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Economic Load Response Participant resource. The submission of demand reduction bids for Economic Load Response

Participant resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. An Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Economic Load Response Participant resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes (less its energy output achievable within ten minutes) from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources located within the metered boundaries of the PJM Region that submit offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market and are capable of providing Secondary Reserve, as specified in the PJM Manuals, shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall be for \$0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and

shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available Synchronized Reserve capability; and the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(B) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(C) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(iii) Offers to Supply Secondary Reserves by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wishes to make their resources available to supply Secondary Reserve shall submit offers to supply Secondary Reserve from such resources, where such offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for \$0.00/MWh. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead

Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting

documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to section 1.10.9 below or Operating Agreement, Schedule 1, section 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

- (a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in section 1.10.1A above. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.
- (b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.
- (c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.
- (d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Operating Agreement, Schedule 1, section 3. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.
- (e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which must equal or exceed 0.1 megawatts, in minimum increments of 0.1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market and/or the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

- (a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.
- (b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.
- (c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.
- (d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.
- (e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve or Non-Synchronized Reserve.
- (f) For energy, hydropower units, excluding pumped storage units, may only be self-scheduled.

1.10.4 Capacity Resources.

- (a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the

Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

(c) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

- (i) enter its election on OASIS by 11:00 a.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and
- (ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in section 1.10.1A above that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in

this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Operating Agreement, Schedule 1, section 3.3A. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.5.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market or Day-ahead Ancillary Services Markets, or the Real-time Energy Market or Real-time Ancillary Services Markets after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth Business Day

following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Energy Market and Day-ahead Ancillary Services Markets.

Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Day-ahead Energy Market, Real-time Energy Market, and Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Operating Agreement, section 18.17.1, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A below:

- i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

- ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or
- iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or
- iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

- (i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost, and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; (6) fixed output indicator; (7) Synchronized Reserve maximum MW; and (8) Secondary Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy, Secondary Reserve, Synchronized Reserve, Non-Synchronized Reserve, or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) Synchronized Reserve maximum MW; (7) Secondary Reserve maximum MW; and (8) for Real-

time Offers only, (i) notification time; (ii) ramp rate; and (iii) for uncommitted hours only, Minimum Run Time.

(c) For Economic Load Response Participant resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the entity controlling a pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Economic Load Response Participant resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Economic Load Response Participant resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Economic Load Response Participant resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Economic Load Response Participant resources will be zero.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Economic Load Response Participant resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve Obligation from its own generation resources and/or Economic Load Response Participant resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve, or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from either available pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the Synchronized Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Market Buyers. The Office of the Interconnection shall clear both the Day-ahead Synchronized Reserve Market and the Real-time Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Synchronized Reserve Market. Resources shall be cleared to provide Synchronized Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Synchronized Reserve offer and the product substitution cost between providing Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy, and of meeting the Synchronized Reserve Requirement, Primary Reserve Requirement, 30-minute Reserve Requirement and Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market shall be committed to provide Synchronized Reserve in the Real-time Synchronized Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product. For any given interval for each Reserve Zone or Reserve Sub-zone, the Office of the Interconnection shall clear Economic Load Response Participant resources in an amount less than or equal to 50 percent of the Minimum Synchronized Reserve Requirement.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Economic Load Response Participant resources from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources capable of providing Non-Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Non-Synchronized Reserve, or by purchases from the PJM Non-Synchronized Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.001. PJMSettlement shall be the Counterparty to the purchases and sales of Non-Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-supply of generation resources by a Market Buyer to satisfy its Non-Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from pool-scheduled generation resources as needed to ensure the Primary Reserve requirement of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the resources providing Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Non-Synchronized Reserve Market and the Real-time Non-Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Non-Synchronized Reserve Market. Resources eligible to sell Non-Synchronized Reserve shall be cleared to provide Non-Synchronized Reserve on the basis of each resource's product substitution cost between providing Non-Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirement, Primary Reserve Requirement, 30-minute Reserve Requirement, and Regulation Requirement..

(c) The Office of the Interconnection shall dispatch generation resources for Non-Synchronized Reserve by sending Non-Synchronized Reserve instructions to generation resources from which Non-Synchronized Reserve is available, in accordance with the PJM Manuals. Market Sellers shall comply with Non-Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Non-Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4C Secondary Reserve.

(a) A Market Buyer may satisfy its Secondary Reserve Obligation by contractual arrangements with other Market Participants able to provide Secondary Reserve, or by purchases from the PJM Secondary Reserve Market at the rates set forth in Operating Agreement, Schedule

1, section 3.2.3A.01. PJMSettlement shall be the Counterparty to the purchases and sales of Secondary Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants.

(b) The Office of the Interconnection shall obtain Secondary Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 30-minute Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by resources providing Synchronized Reserve and resources providing Non-Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Secondary Reserve Market and the Real-time Secondary Reserve Market in accordance with the applicable Operating Reserve Demand Curves established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market and the offers submitted in the Secondary Reserve Market. Resources shall be cleared to provide Secondary Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Secondary Reserve offer and the product substitution cost between providing Secondary Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirement, Primary Reserve Requirement, 30-minute Reserve Requirement and Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes greater but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Secondary Reserve in the Day-ahead Secondary Reserve Market shall be committed to provide Secondary Reserve in the Real-time Secondary Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product. For any given interval for each Reserve Zone or Reserve Sub-zone, the Office of the Interconnection shall clear Economic Load Response Participant resources in an amount less than or equal to 50 percent of the Minimum 30-minute Reserve Requirement.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Secondary Reserve by sending Secondary Reserve instructions to generation resources and/or Economic Load Response Participant resources from which Secondary Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

The Office of the Interconnection shall update the information posted on the PJM Open Access Same-time Information System to reflect its dispatch of generation resources.

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained economic dispatch, which is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load buses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers, except that generation resources will be dispatched in economic merit order but limited to \$2,000/megawatt-hour for purposes of calculating Locational Marginal Prices. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Operating Agreement, Schedule 1, section 2.3. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants, Pre-Emergency Load Response Program participants and Emergency Load Response Program participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Operating Agreement, Schedule 1, section 2.4, every qualified offer for demand reduction and of energy by a Market Seller from resources that are dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified offers from Economic Load Response Participants in either the Day-ahead or Real-time Energy Markets or from participants in either the Emergency Load Response Program or Pre-Emergency Load Response Program in the Real-time Energy Market.

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region, in the manner described in Operating

Agreement, Schedule 1, section 2.5. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

- (d)
 - (i) The Office of the Interconnection shall use its day-ahead market clearing software to forecast if the Office of the Interconnection will experience a shortage of the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement and/or the Minimum Synchronized Reserve Requirement as further described in the PJM Manuals. If the day-ahead market clearing software forecasts that a shortage of any of the minimum reserve requirement(s) exists, the Office of the Interconnection shall implement shortage pricing through the inclusion of the applicable Reserve Penalty Factor(s) in the Day-ahead Locational Marginal Prices. Shortage pricing shall exist until the day-ahead market clearing software is able to meet the specified minimum reserve requirements.
 - (ii) The Office of the Interconnection shall use its real-time security-constrained economic dispatch software program to determine if the Office of the Interconnection is experiencing a shortage of the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement and/or the Minimum Synchronized Reserve Requirement as further described in the PJM Manuals. If the real-time security-constrained economic dispatch software program determines that a shortage of any of the minimum reserve requirement(s) exists, the Office of the Interconnection shall implement shortage pricing through the inclusion of the applicable Reserve Penalty Factor(s) in the Real-time Locational Marginal Price software program. Shortage pricing shall exist until the real-time security-constrained economic dispatch solution is able to meet the specified minimum reserve requirements and there is no Voltage Reduction Action or Manual Load Dump Action in effect. If a shortage of the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement and/or the Minimum Synchronized Reserve Requirement exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem with or malfunction of the security-constrained economic dispatch software program, including but not limited to program failures or data input failures, the Office of the Interconnection will utilize the best available alternate data sources to determine if a Reserve Zone or Reserve Sub-zone is experiencing a shortage of the applicable minimum reserve requirement.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and utilized in the PJM security-constrained economic dispatch algorithm and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Operating Agreement, Schedule 1, section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made 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 Operating Reserve Demand Curves, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by an Economic Load Response Participant resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by an Economic Load Response Participant resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by an Economic Load Response Participant resource based on the effect of increased generation from or consumption by the resource on transmission losses.

(b) The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the applicable Operating Reserve Demand Curves. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange.

(c) The Office of the Interconnection shall issue day-ahead alerts to PJM Members of the possible need to use emergency procedures during the following Operating Day. Such emergency procedures may be required to alleviate real-time emergency conditions such as a transmission emergency or potential reserve shortage. The alerts issued by the Office of the Interconnection may include, but are not limited to, the Maximum Emergency Generation Alert, Primary Reserve Alert and/or Voltage Reduction Alert. These alerts shall be issued to keep all affected system personnel informed of the forecasted status of the PJM bulk power system. The Office of the Interconnection shall notify PJM Members of all alerts and the cancellation thereof via the methods described in the PJM Manuals. The alerts shall be issued as soon as practicable to allow PJM Members sufficient time to prepare for such operating conditions. The day-ahead alerts issued by the Office of the Interconnection are for informational purposes only and by themselves will not impact price calculation during the Operating Day.

(d) The Office of the Interconnection shall issue a warning of impending operating reserve shortage and other emergency conditions in real-time to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM bulk power system. Such warnings will generally precede any associated action taken to address the shortage conditions. The Office of the Interconnection shall notify PJM Members of the issuance and cancellation of emergency procedures via the methods described in the PJM Manuals. The warnings that the Office of the Interconnection may issue include, but are not limited to, the Primary Reserve Warning, Voltage Reduction Warning, and Manual Load Dump Warning.

The purpose of the Primary Reserve Warning is to warn members that the available Primary Reserve may be less than the Minimum Primary Reserve Requirement. If the Primary Reserve shortage condition was determined as described in Operating Agreement, Schedule 1, section 2.2(d), the applicable Reserve Penalty Factor is incorporated into the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable.

The purpose of the Voltage Reduction Warning is to warn PJM Members that the available Synchronized Reserve may be less than the Minimum Synchronized Reserve Requirement and that a voltage reduction may be required. Following the Voltage Reduction Warning, the Office of the Interconnection may issue a Voltage Reduction Action during which it directs PJM Members to initiate a voltage reduction. If the Office of the Interconnection issues a Voltage Reduction Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement and the Minimum Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price as applicable. The Reserve Penalty Factors for the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement and the Minimum Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price calculation, as applicable, until the Voltage Reduction Action has been terminated.

The purpose of the Manual Load Dump Warning is to warn members that dumping load may be necessary to maintain reliability. Following the Manual Load Dump Warning, the Office of the Interconnection may commence a Manual Load Dump Action during which it directs PJM Members to initiate a manual load dump pursuant to the procedures described in the PJM Manuals. If the Office of the Interconnection issues a Manual Load Dump Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement and the Minimum Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price as applicable. The Reserve Penalty Factors for the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement and the Minimum Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market

Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price calculation, as applicable, until the Manual Load Dump Action has been terminated.

Shortage pricing will be terminated in a Reserve Zone or Reserve Sub-Zone when demand and minimum reserve requirements can be fully satisfied with generation and Economic Load Response Participant resources and any Voltage Reduction Action and/or Manual Load Dump Action taken for that Reserve Zone or Reserve Sub-Zone has also been terminated.

(e) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing the Real-time Prices based on system conditions during the preceding interval.

2.6 Calculation of Day-ahead Prices.

(a) For the Day-ahead Energy Market, day-ahead Locational Marginal Prices shall be determined on the basis of the least-cost, security-constrained dispatch, model flows and system conditions resulting from the load specifications (including PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads that they serve), offers for generation, dispatchable load, Increment Offers, Decrement Bids, offers for demand reductions, and bilateral transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Such prices shall be determined in accordance with the provisions of this section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy and reserve costs, given scheduled system conditions, scheduled transmission outages, any transmission limitations that may exist, and a set of Operating Reserve Demand Curves. This calculation shall be made by applying a joint optimization of energy and reserves, given scheduled system conditions, a set of energy offers, a set of reserve offers, a set of Operating Reserve Demand Curves, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing consumption by an Economic Load Response Participant resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by an Economic Load Response Participant resource based on the effect of increased generation from or consumption by the resource on transmission line losses.

(b) The day-ahead Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the impact of the applicable Operating Reserve Demand Curves. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Operating Agreement, Schedule 1, section 2.

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market performance clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

$\text{Regulation Charge} = \text{Hourly Regulation Obligation Share} * (\text{sum of the Real-time Settlement Interval Regulation credits in an hour})$

(b) Each Market Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to section 3.2.2A.1 below, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 below shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in Operating Agreement, Schedule 1, section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the

generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Economic Load Response Participant resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour in accordance with the PJM Manuals and below.

The unit-specific opportunity cost incurred during the Real-time Settlement Interval in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Economic Load Response Participant resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during each of the preceding three Real-time Settlement Intervals of the shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the preceding three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding three Real-time Settlement Intervals of the shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating Real-time Settlement Interval) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following three Real-time Settlement Intervals of the shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the following three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following three Real-time Settlement Intervals of the shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy

Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the Regulation market performance-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the Regulation market performance-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the Regulation market performance-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the Regulation market capability-clearing price for each Regulation Zone by subtracting the Regulation market performance-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the Regulation market capability-clearing price for that market Real-time Settlement Interval.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. Resources following the dynamic Regulation signal which have a unit-specific benefits factor less than 0.1 will not be considered for the purposes of committing resources. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta, \delta+5 \text{ Min})};$$

$\delta=0 \text{ to } 5 \text{ Min}$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs} ((\delta - 5 \text{ Minutes}) / (5 \text{ Minutes})).$$

The Office of the Interconnection shall calculate an energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ϵ) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs} (\text{Error});$$

$$\text{Error} = \text{Average of Abs} ((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})); \text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

$$\text{Accuracy Score} = \max ((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

The historic accuracy score will be based on a rolling average of the Real-time Settlement Interval accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1A(e). A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three

suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Tariff, Attachment K-Appendix, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 and the parallel provision of Operating Agreement, Schedule 1, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 does not meet the Minimum Synchronized Reserve Requirement, the Minimum Primary Reserve Requirement, and the Minimum 30-minute Reserve Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Tariff, Attachment K-Appendix, section 1.7.17 and the parallel provision of Operating Agreement, Schedule 1, section 1.7.17, and Tariff, Attachment K-Appendix, section 1.10 and the parallel provision of Operating Agreement, Schedule 1, section 1.10. In addition, the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in section 3.2.3(n) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to section 3.2.3(p) below, depending on whether the balancing Operating Reserve

credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day. *Allocation to real-time load share under this subsection (b) shall not apply to Direct Charging Energy.*

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less

than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with section 3.2.3(b) plus any unallocated charges from section 3.2.3(h) and Operating Agreement, Schedule 1, 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load ((a) net of Behind The Meter Generation expected to be operating, but not to be less than zero; and (b) *excluding Direct Charging Energy*) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Operating Agreement, Schedule 1, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-

time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or charge for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Economic Load Response Participant resources) costs for generation resources.

Except as provided in section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to section 3.2.3(b), and less the absolute value

of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below, and less any amounts credited for providing Reactive Services as specified in section 3.2.3B, and less the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding Real-time Settlement Interval(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3(f).
- (ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement

Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:

- 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A \times B) - (C + D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or
- 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and

the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Operating Agreement, Schedule 1, section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, shall be allocated and charged to each Market Participant based on their daily total of hourly deviations determined in accordance with the following equation:

$$\sum_h (A + B + C)$$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12 are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in section 3.2.3(q) below, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

- (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.
- (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed

Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of Supply or Demand deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) *excluding Direct Charging Energy*) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared (“Maximum Generation Emergency Alert”); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by section 3.2.3(b) or section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions

described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as “MaxGen Conditions”). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Operating Agreement, Schedule 2, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Operating Agreement, Schedule 1, section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Operating Agreement, Schedule 1, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Operating Agreement, Schedule 1, section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller’s lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to section 3.2.3(e) plus the Real-time Energy Market revenues for the Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time Settlement Intervals required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller’s lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to \$1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units

when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed \$1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described below and in the PJM Manuals.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum $\leq$ 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum $\geq$ 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\text{Ramp\_Request}_t = \frac{(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSLAtime}_{t-1})}$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1} \right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value for each Real-time Settlement Interval. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW for each Real-time Settlement Interval.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is ≤ 10 , or its Real-time Settlement Interval MWh is within 5% of the Real-time Settlement Interval ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined for each Real-time Settlement Interval in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.
- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – UDS LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW.
- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

(o-1) Dispatchable Economic Load Response Participant resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in Operating Agreement, Schedule 1, section 3.3A. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Operating Agreement, Schedule 1, section 3.2.3(h) except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating

Day. Allocation to real-time load share under this subsection (p) shall not apply to Direct Charging Energy.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceeds the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Operating Agreement, Schedule 1, section 3.2.3(h)(ii)(A) to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC, OVEC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with section 3.2.3(p). *Allocation to real-time load share under this subsection (q)(i) shall not apply to Direct Charging Energy.*

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Operating Agreement, Schedule 1, section 3.2.3(q)(i). The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with section 3.2.3(p). *Allocation to real-time load share under this subsection (q)(ii) shall not apply to Direct Charging Energy.*

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than \$1,000/MWh as determined in accordance with the Market Seller's

PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2 and PJM Manual 15, but are not verified at the time of dispatch of the resource under Operating Agreement, Schedule 1, section 6.4.3, or greater than \$2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than \$2,000/MWh, and costs greater than \$1,000/MWh which were not verified at the time of dispatch of the resource under Operating Agreement, Schedule 1, section 6.4.3. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market shall be equal to the product of the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide.

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the

sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of

demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirement, Minimum Primary Reserve Requirement and the Minimum Synchronized Reserve Requirement for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the Minimum Synchronized Reserve Requirement shall be \$2,000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for Synchronized Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Synchronized Reserve Market Clearing Price in each hour of the Day-ahead Synchronized Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resource shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B = The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, capped at the amount of Synchronized Reserve the resource responded during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A] plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

- (A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;
- (B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;
- (C) A resource's Final Offer is less than its Committed Offer;
- (D) A resource trips offline or otherwise becomes unavailable in real-time;
- (E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or
- (F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B + C + D) - (E + F + G + H)$$

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

(g) [Reserved for future use]

(h) For each operating hour, the sum of the Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its real-time purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource, in excess of the amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Synchronized Reserve in real-time on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price for all intervals the resource was assigned or self-scheduled to provide Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or an Economic Load Response Participant resource, except for Batch Load Economic Load Response Participant Resources covered by section 3.2.3A(l) below, is the difference between the generation resource's output or the Economic Load Response Participant resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Economic Load Response Participant resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to an Economic Load Response Participant resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Economic Load Response Participant Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Economic Load Response Participant Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

(b) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows: .

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the Operating Reserve Demand Curve for Primary Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute.

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the Operating Reserve Demand Curve for

Primary Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Non-Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirement and the Minimum Primary Reserve Requirement for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the Minimum Primary Reserve Requirement shall be \$2,000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for Primary Reserve are warranted for subsequent Delivery Year(s).

(d) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non-Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(\text{zero}) - (A + B + C + D)$$

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

(e) [Reserved for future use]

(f) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and

its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous Real-time Settlement Interval the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for 30-minute Reserve for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary

Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for 30-minute Reserve for that Reserve Zone or Reserve Sub-zone plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the sum of the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirements for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the Minimum 30-minute Reserve Requirement shall be \$2000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve prices exceeding \$2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for 30-minute Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation

resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time

Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero,

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B) - (C + D + E + F)$$

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

(a) Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing 30-minute Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet reliability requirements in light of supply and demand uncertainties. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with subsection (b) and the PJM Manuals.

(b) Methodology for Establishing Operating Reserve Demand Curves

For each three-month season, Winter (December through February), Spring (March through May), Summer (June through August), and Fall (September through November), and for each time-of-day block set forth in the PJM Manuals, the Office of the Interconnection shall establish Operating Reserve Demand Curves for each Reserve Zone or Reserve Sub-zone as follows:

(i) Each Operating Reserve Demand Curve shall be plotted on a graph on which megawatts of reserve is on the x-axis and price is on the y-axis;

(ii) The Operating Reserve Demand Curve for each Reserve Zone or Reserve Sub-zone shall be plotted by combining (i) a straight horizontal line starting from point (1) on the y-axis to point (2), (ii) a straight vertical line connecting points (2) and (3), and (iv) a curved line from point (3) to the x-axis, where:

(A) Point (1) is the point on the y-axis(price) equal to the Reserve Penalty Factor for the minimum reserve requirement for the subject reserve requirement (i.e., the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement, or the Minimum Synchronized Reserve Requirement);

(B) Point (2) has the y-axis coordinate of point (1) and the x-axis coordinate of the applicable minimum reserve requirement as determined for the Reserve Zone or Reserve Sub-zone in accordance with the PJM Manuals;

(C) Point (3) has the x-axis coordinate of the applicable minimum reserve requirement and the y-axis coordinate resulting from multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring an infinitesimal amount of additional MW of reserves beyond the minimum reserve requirement; and

(D) From point (3) to the x-axis, first, the Office of the Interconnection develops a curve starting at point (3). The shape of the curve will be determined by multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring each additional MW of reserves beyond the minimum reserve requirement until the resulting product falls below \$0.01/MWh at which point the curve will intersect with the x-axis. These probabilities are calculated from an empirical distribution of data from a rolling three-calendar year period of the following supply and demand uncertainties, using a 30-minute time horizon for clearing Primary Reserves and Synchronized Reserves and a 60-minute time horizon for clearing 30-minute Reserves: load forecast error, wind forecast error, solar forecast error, and forced outages of thermal units, and, for the Operating Reserve Demand Curves for 30-minute Reserves only, net interchange forecast error, all as described in the PJM Manuals. The empirical distribution also accounts for the Regulation requirement, expressed in effective megawatts, that PJM has established for each hour within that time-of-day block, by reducing the magnitude of the above uncertainties by the requirement.

The Office of the Interconnection will post each Operating Reserve Demand Curve used to clear reserve markets.

(c) Annual Update of Operating Reserve Demand Curves

On an annual basis, the Office of the Interconnection shall update the determination of the probability of falling below the applicable minimum reserve requirement, including each uncertainty, to account for the most recent calendar year's data, in accordance with the PJM Manuals, and post revised Operating Reserve Demand Curves by April 1. The revised Operating Reserve Demand Curves shall become effective June 1, coincident with the start of the next Delivery Year.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to $\{(AG - LMP_{DMW}) \times (UB - URTLMP)\}$ where:

AG equals the actual output of the unit;

LMP_{DMW} equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the lesser of the Final Offer or Committed Offer;

URLTMP equals the real time LMP at the unit's bus; and

where $UB - URTLMP$ shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation,

taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on

whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) *excluding Direct Charging Energy*) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the applicable Synchronized Reserve Requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the

end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's applicable interval cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the applicable interval product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (*(a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy*) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.6 Emergency Energy.

- (a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at \$2,000/MWh, provided that the Emergency energy is needed to meet demand in the PJM Region.
- (b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.
- (c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.
- (d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

- (a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in Operating Agreement, Schedule 1, sections 3.2.1 through 3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.
- (b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, section 14 include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market

Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

Attachment C

**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-____-000
	)	
PJM Interconnection, L.L.C.	)	Docket No. EL19-____-000

**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 affidavit on behalf of PJM Interconnection, L.L.C. (“PJM”) to support its reserve market reforms in this proceeding. Our qualifications are provided as Exhibits 2 and 3 to this affidavit.
2. In November, 2018, PJM engaged FTI Consulting, Inc., 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 is provided as Exhibit 1 to this affidavit.
3. In this affidavit we affirm and adopt, as if set forth in this affidavit, the analysis and all findings and conclusions contained in the PJM ORDC Report, including the Appendix thereto, to provide support for PJM’s proposal to reform its ORDC. As we find in the PJM ORDC Report, PJM’s existing operating reserve market rules do not support just and reasonable rates. The existing PJM operating reserve market design fails to support economic efficiency in several ways. Elements of the current operating reserve market construct in PJM were developed in stages in prior years and, as a result, are not explicitly founded in a principled theory connecting the composite operating reserve market design to sustainable, just and reasonable rates. In addition, changing circumstances, such as increasing variability in net load due to intermittent resources, have revealed problems where the prices for different types of reserves do not reflect their underlying economic values or provide the needed support for efficient, reliable operation.
4. 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. As we also find in the PJM ORDC Report, 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.

Exhibits to Attachment C

Attachment C
Exhibit 1

PJM ORDC Report

PJM Reserve Markets: Operating Reserve Demand Curve Enhancements

William W. Hogan, Harvard University

Susan L. Pope, FTI Consulting Inc.

March 21, 2019

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PJM Reserve Markets: Operating Reserve Demand Curve Enhancements

William W. Hogan¹, Harvard University

Susan L. Pope, FTI Consulting Inc.

March 21, 2019

Overview

Organized electricity markets require attention to the details of market design, i.e., the tariff rules and software models used to determine the quantities clearing in the markets and the prices used for settlements. The requirement for open and non-discriminatory access to the transmission grid makes it essential to get the prices right to provide incentives for coordinated but largely voluntary actions by market participants that are economically efficient and reinforce reliable grid operations. The basic market design for transmission access and energy market clearing in place in PJM addresses this fundamental challenge of non-discriminatory open access. Refinements for pricing of operating reserves are an important opportunity to enhance the PJM market design to better value reserves and improve pricing under scarcity conditions.

This paper addresses the underlying economic efficiency elements of PJM's proposed Operating Reserve Demand Curve reforms that provide a basis for just and reasonable rates. As summarized here and discussed further by PJM¹, the existing PJM operating reserve market design fails to support economic efficiency in a number of ways. Elements of the current operating reserve market construct in PJM were developed in stages in prior years and, as a result, are not explicitly founded in a principled theory connecting the composite operating reserve market design to sustainable, just and reasonable rates. In addition, changing circumstances, such as increasing variability in net load due to intermittent resources, have revealed problems where the prices for different types of reserves do not reflect their underlying economic values or provide the needed support for efficient, reliable operation. 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.

¹ Affidavits of Adam Keech, Christopher Pilog and Patricio Rocha Garrido contained as Attachments D, E, and F to the Reserve Market Pricing Reform Package submitted by PJM to the Federal Energy Regulatory Commission on March 29, 2019

The PJM proposal is to consolidate and redefine the types of operating reserves it schedules in its day-ahead and real-time markets and to introduce Operating Reserve Demand Curve (ORDC) reforms that reflects the value of incremental operating reserves of different types and in different locations. This will enable energy and reserve pricing that better reflect the value of reserves under different operating conditions and will also support consistency in operating reserve pricing between PJM's day-ahead and real-time markets. Implementation of the desired enhancements requires policy choices and modeling decisions to enable a workable representation of the demand for operating reserves.

The discussion in this paper provides a theoretical basis for the formulation of operating reserve demand curves and the co-optimization of energy and reserve markets given these reserve demand curves. The resulting clearing prices for reserves and energy are connected to economic efficiency because they are derived from a model of co-optimized economic dispatch. The initial model presented, for energy and a single type of reserves, is extended to incorporate further features relevant to the scheduling of operating reserves, including multiple types of reserves, the activation of emergency response, locational operating reserve requirements, and day-ahead markets.

PJM's proposed design choices for its operating reserve demand curves have been made with purpose to align with the underlying theory to the extent possible and implement a market design that better meets the standard of just and reasonable rates. PJM's ORDC reform proposal is an important step toward improving the efficiency of PJM's electricity markets and achieving just and reasonable rates relative to the current problematic and unjust operating reserve market design.

PJM Operating Reserve Demand Curve Proposal

The existing PJM operating reserves design includes two classes: Tier 1 and Tier 2 reserves. Tier 1 reserves have an assumed 10-minute response time provided by flexible generation resources available after the real-time economic dispatch. This includes available capacity on partially dispatched synchronized resources. Put simply, Tier 1 is the amount of available capacity that is assumed to be available in ten minutes from a resource that is online for the purposes of producing energy. These reserves are not formally procured and have been treated as being free. By contrast, Tier 2 consists of generating resources whose real-time dispatch is reduced from their economic set point, so the Tier 2 resources incur opportunity costs in providing reserves. Tier 2 resources are paid these opportunity costs during the same dispatches when Tier 1 resources provide the same reserve product for free.

The operational requirements and payments for Tier 1 and Tier 2 reserves are not consistent, leading to unjust and unreasonable prices. Tier 1 resources do not have an obligation to respond and are not paid the market-clearing price of reserves set by the opportunity cost of the marginal Tier 2 resource. By contrast, Tier 2 resources are obligated to respond if activated and are paid a market-clearing opportunity cost price for reserves regardless of deployment. As a result of this

inconsistency in pricing and operational requirements, PJM has found the average Tier 1 response rate has been 60.1%, whereas the Tier 2 average response rate has been 87.6%. The inconsistency in the prices of the reserves is not just and reasonable, and the inconsistency in the performance of the reserves is a matter of concern for reliable system operation.

A further problem is that PJM's current pricing structure for operating reserves does not derive from an assessment of the value of operating reserves. There is a minimum reserve requirement (MRR) derived from North American Electric Reliability Corporation (NERC) standards, and PJM sets "penalty" factors used to set reserve prices when reserves would fall below this level absent various unpriced operator actions. The current maximum penalty factor is \$850/MWh, which is below the costs of many of the actions operators must take to avoid violating the MRR. Because the penalty factor is lower than the cost of these actions, it will not provide a market price signal to call forth voluntary provision of additional reserves at prices lower than the cost of the mandatory emergency actions. This results in operator interventions that might not be necessary with a higher penalty price. This impacts settlements across the energy and reserves markets, because when interventions occur they can deploy more reserves than are necessary to resolve a shortage (e.g., by activation of a block of demand response), which can suppress energy and reserve prices and increase uplift costs. The \$850/MWh maximum penalty factor is also far less than the Value of Lost Load (VOLL) that would be relevant in determining the marginal value of additional reserves in the event of involuntary load curtailment that might be required to avoid cascading system failures.

Implementation of the existing design, especially given changing operating conditions, yields energy and operating reserve prices in PJM that do not align with economic principles. The prices of incremental reserves and energy can deviate from incremental cost and are not consistent with the implications of first principles for determining the value of operating reserves when supply is constrained. These inconsistencies with economic principles support the conclusion that the existing system for operating reserves and their associated pricing is not just and reasonable.

The main elements of the PJM reform proposal include consolidation, by removing the Tier 1 synchronized reserve product, and replacing the Tier 2 reserves with a new structure of reserve requirements to align better with operating requirements. The proposal is for real-time markets for 10-minute synchronized reserves, primary (non-synchronized) operating reserves, and 30-minute reserves, and corresponding day-ahead markets for the same products: 10-minute synchronized and primary reserve, as well as 30-minute reserves.

These reserve product markets will include an enhanced ORDC anchored by an increase of the maximum "penalty" factor from \$850/MWh to \$2,000/MWh to improve scarcity pricing and replace operator intervention with market response to higher prices. The design proposal includes a cascaded hierarchy in the requirements for reserves with different response times, and this hierarchy flows through into their relative prices. For example, synchronized reserves can meet the primary requirement, and the 30-minute requirement. Hence, as discussed in the Appendix,

the price for synchronized reserves is the sum of the clearing prices for all three of these reserves types and the levels that can be reached are consistent with reasonable estimates of the range of VOLLs.

The PJM ORDC reform addresses the value of incremental operating reserves that are both below and above the MRR. The value of reserves of different amounts is the probability that, with a given level of scheduled reserves, PJM's actual reserves in real-time will fall below the MRR and require some form of operator intervention. PJM's proposed Probability of Reserves Falling Below the Minimum Reserve Requirement (PBMRR) is similar to the familiar loss of load probability (Lolp) and produces a downward sloping demand curve for additional operating reserves starting from the MRR quantity, at which the price is equal to the penalty factor. The penalty factor anchoring the ORDC is the maximum price paid for incremental reserves when PJM is taking emergency action. The downward sloping PBMRR recognizes that the scarcity value of reserve capacity does not suddenly drop to zero just beyond the MRR, as PJM's ORDC effectively does now. The ORDC reform recognizes the value of scheduled reserves greater than the MRR, which in practice contribute to PJM's reserves not falling below the MRR during actual real-time operation.

When combined with simultaneous optimization of the energy and reserve dispatch, the ORDCs proposed by PJM enable internally consistent prices for energy and reserves at the margin. The improvements will avoid PJM taking emergency action when it faces uncertainty about the actual response of (Tier 1) reserves, because its prices are too low to call forth voluntary supplies of economic reserves, or because of an inability to co-optimize and reconfigure how available resources are assigned to provide reserves versus energy in real-time.

The existing PJM market design includes the basic elements of an ORDC through two levels of penalty factor when operating reserves fall to certain reserve thresholds. But this design is inadequate. It does not recognize the true value of reserves along a continuum derived from the probabilistic representation of the expected need for additional reserves in real-time. Additionally, the maximum penalty price falls short of the cost of actions the PJM system operator currently takes in order to restore operating reserves. This leaves market participants exposed to the impact of out of market decisions which undermines confidence by PJM market participants that the prices in the markets will be the result of competitive market forces. PJM's market design must be enhanced to ensure reserves are priced consistently with their value, and consistently across energy and reserve products.

The details of the ORDC reform implementation are important, especially those that connect to the fundamentals of efficient electricity market design. The proposed ORDC structure builds on a foundation of electricity market design principles and adopts workable implementations that conform to its energy dispatch models. By building internally consistent connections between its reserves and energy markets, which are founded in system operation and flow through into pricing,

the PJM ORDC design will greatly improve the justness and reasonableness of its energy and operating reserve prices and provide the framework for future improvements.

Fundamentals of Electricity Market Design

The electricity system presents three unusual characteristics that have a profound effect on any electricity market design. First, unlike other commodities, electricity supply and demand must maintain constant balance under rapidly changing conditions. Second, power flows along parallel paths through the transmission system as dictated by physics and the locations of generation and load. Third, the speed of response of the physical system necessitates a variety of reliability constraints to ensure that secure power balance continues under sudden changes in the system conditions.

One implication of these characteristics is that power dispatch requires explicit coordination. With current technology it is not possible to maintain security or achieve efficiency with a purely decentralized system. Hence, a ubiquitous feature of electricity systems is the need for and presence of a system operator, such as PJM.

To maintain secure operation, the system operator must enforce the various reliability constraints to ensure that in the event of a contingency the system response will be such that the physical power flows will remain within the specified limits. This requires maintaining reserves of generation and load-response, while monitoring pre-and-post contingency power flows.

To achieve economic efficiency, the coordinated dispatch must maximize social welfare, i.e., the benefits of load minus the costs of generation, subject to the various reliability constraints. This is a challenging problem, and over the decades the industry has steadily advanced its capabilities to represent and optimize over the inter-related physics, economics, and policy requirements (Ott, 2003).

In many regions, coordinated electricity markets have been introduced to reduce or eliminate the role of monopoly operation, procurement and resource planning in achieving the benefits of coordinated dispatch. In these regions, such as PJM, energy and ancillary services markets are designed to work together to provide price signals for operations and help support investment in an electricity system configuration capable of delivering intended levels of reliability to customers at an economically efficient cost.

The accuracy of the real-time price signal, in terms of sending a high price when the supply (i.e., energy plus reserves) is constrained, or a low price during times of abundant supply, is a lynchpin of efficient electricity market design. Real-time dispatch and pricing corresponding closely to the physical requirements of reliable system operation reduce the need to devise alternative, non-market mechanisms to guarantee that the Independent System Operator (ISO) has the needed resources at the right times. It is essential to continue to improve the real-time coordinated dispatch

and associated settlements by providing strong real-time price signals for resources that are most economic, because they provide energy and reserves when and where they are most needed and most valuable in real-time.

Security-Constrained Economic Dispatch with Locational Prices

The electricity market design has successfully confronted the challenges of non-discriminatory open access and the simultaneous need for coordination of power flows on the grid. It requires explicit modeling of physical operating constraints and specification of the welfare-maximizing economic objective function, yielding both the economic dispatch (for energy and operating reserve schedules) and prices supportive of the desired optimized dispatch. The market cannot solve the problem of market design. The system operators and regulatory oversight authorities have the problem of making and improving the design choices to build this model. Application of the basic theory of economic dispatch, and the experience of costly mistakes, reinforce the same conclusion: the foundation of successful market design is bid-based, security-constrained, economic dispatch with locational marginal prices and financial transmission rights (Hogan, 2002). This is the basic framework in PJM.

A criterion imposed on the design of markets for energy and operating reserves is that the dispatch, schedules and prices should be ruled by the practices for secure system operation and the decisions made by the system operator. The bids and offers come from load and generation and present the system operator with a set of choices for dispatch and schedules (with different prices) to meet the many constraints, including the transmission constraints. Differences in the marginal impact on the cost of losses and the marginal impact on the cost of respecting physical limits cause the marginal value of generation and marginal cost of serving an increment of load to differ across locations. Efficient dispatch produces the marginal costs of losses and the marginal cost of respecting physical constraints; the marginal values of generation supply and load consumption are identically the same thing as the locational prices. Contracts in forward markets can be settled at these locational prices and financial transmission rights provide a mechanism for hedging the locational differences in prices (Hogan, 1992).

An important property of this market design, based on economic optimization constrained by the physical constraints imposed for secure operation of the transmission system, is that the resulting locational prices support the actual economic dispatch. This means that, with limited exceptions, all that is required to incent suppliers and loads to follow their dispatch signal is to pay or charge them the market-clearing price. Given certain usual simplifying assumptions about the underlying cost structure, which includes convex total cost offers, generators and loads who acted as price-takers would have no incentive to deviate from the economic dispatch. This basic model of security-constrained economic dispatch and locational pricing is the only pricing model that is consistent both with efficient dispatch and with the principles of open access and non-discrimination. Any other pricing model would create incentives to deviate from the dispatch and

would require some departure from open access or non-discrimination in order to maintain dispatch efficiency.

This basic outline summarizes the key reasons for the importance of getting the prices right. Now, after two decades of experience, all the organized markets in the United States build on these foundations in their market design.

PJM has been a pioneer and has moved steadily to adopt industry best practice for dispatch and pricing in their real-time energy market in order to harness market forces to support minute-by-minute reliability. The PJM implementation of Locational Marginal Pricing (LMP) was a central step in recognizing that economically efficient prices supportive of minute-by-minute reliability must vary to reflect locational differences in the value of energy when there are active transmission constraints. Similarly, the ORDC reform proposal is needed to recognize that efficient energy and reserve prices supportive of minute-by-minute reliability must consistently reflect differences in the value of operating reserves with different responsive lead-times and located in different locations.

Co-Optimization of Energy and Reserve Markets

As an improvement on the basic market design, co-optimized dispatch of energy and reserves is recognized as the market design standard in order to reliably and economically position resources of all types, including generation, load, imports and exports. PJM utilizes co-optimization and it is central to their ORDC reform proposal. As intermittent energy production increases, it will increase the frequency with which PJM will need to direct resources to ramp up or down to balance the system's net load and maintain required levels of reserves. PJM uses a co-optimized security-constrained economic dispatch (SCED) to look at all of the bids and offers for energy and operating reserves at the same time, while also taking into account all operational constraints (such as ramping constraints, transmission system contingencies, etc.) and issue simultaneous real-time dispatch instructions for energy and schedules for operating reserves. The objective function for the co-optimized SCED is the welfare maximization defining economic efficiency.

As intermittent production increases, co-optimized dispatch of energy and operating reserves, with ORDCs reflecting the economic value of incremental reserves, automatically will efficiently adjust the output of the resources that can increase or decrease production at least cost to balance load, taking into account ramping constraints, reserve requirements and possible contingencies. Co-optimized real-time dispatch of energy and operating reserves markets, coupled with dispatch interval settlements and improvements to the ORDC, mean suppliers will be paid a price that better reflects the value of the services that they are providing. Under this market design, resources make bids and offers into the real-time dispatch based on their estimated costs of operation. The co-optimization dispatches and/or schedules their capacity for its highest-value use (whether reserves or energy, in particular) from the standpoint of maximizing social welfare. The supplier will be paid the market-clearing price for its real-time supply of energy and operating reserves, not its

offer or bid price, thus supporting the least-cost dispatch. Importantly, co-optimization produces consistent prices for energy and reserves. In particular, the demand for reserves represented by the ORDC provides a market-clearing scarcity price for reserves that also enters into the formation of the clearing-price for energy.

Economic efficiency improves because the co-optimized SCED with ORDC provides the incentive for bids and offers to enable the least-cost combination of resources to be used to provide energy and ancillary services (such as operating reserves) in real-time, and because improved prices for these products will more efficiently incent market entry and exit.

Day-Ahead Markets

The basic market design principles described for real-time also affect any coordinated forward markets operated by the system operator, such as the day-ahead market in PJM. The forward markets create financial contracts for settlement against real-time prices. The benefits include hedging for supply, demand and transmission constraints, and the opportunity for a centralized look-ahead to insure the unit commitment will ensure real-time reliability. In addition, a day-ahead market allows for broader participation by financial entities, known as virtual bidders, who do not plan physical delivery in real-time but provide added liquidity and therefore competition in the day-ahead markets (Hogan, 2016).

The complete design of electricity markets based on security-constrained economic dispatch and locational prices is a challenging task. If the industry had not already developed many of the essential economic dispatch tools, electricity restructuring as we know it may not have been possible. The basic model focused on pricing real power flows, and there have been many simplifications required to achieve workable and auditable approximations for the dispatch and associated prices consistent with the many complexities of electricity system operation. For example, the treatment of reactive power flows, ancillary services such as black start and frequency response, unit commitment and other dynamic constraints, is a partial list of the details that must be considered by system operators but which are treated with approximations in the economic optimization and pricing model. The process has been to work steadily to improve price formation, and to address as needed the related problems that arise with the successful implementation of the necessarily imperfect approximations.

Scarcity Pricing

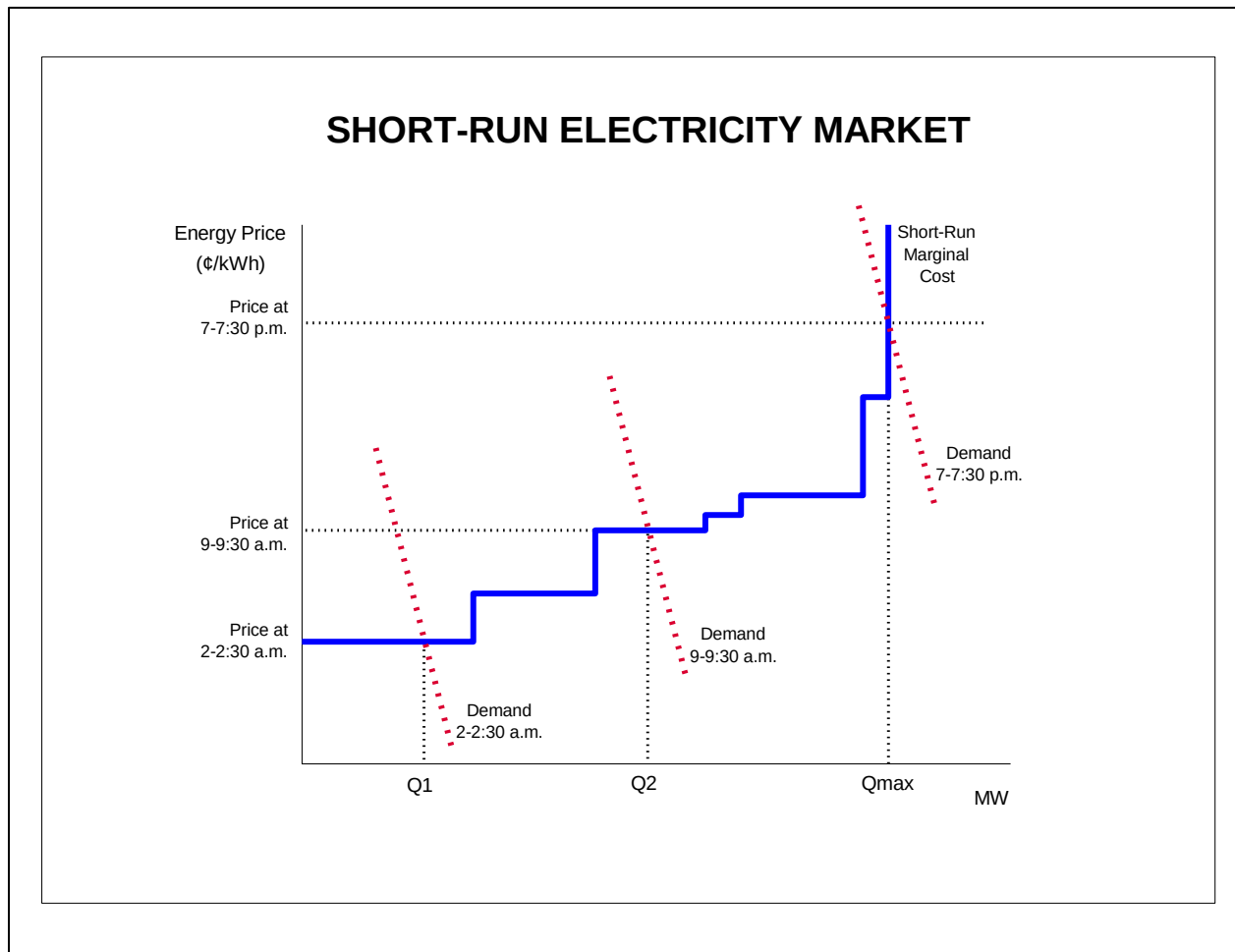
Scarcity pricing is an important example where an extension of the basic market design is needed to address a pricing problem arising with increasing frequency. There is a need to enhance the basic market design to provide prices that better reflect the cost of scarcity when the system is pressing against its capacity limits. This section focuses on the underlying principles of scarcity pricing and how the objective of implementing scarcity pricing drives the proposed PJM enhancements of the characterization of the short-term value of operating reserves through the ORDCs.

Early on in the development of workable market designs it was clear that prices did not fully reflect the marginal value of generation during scarce conditions (Joskow, 2008), and this is a continuing concern (Joskow, 2019). This impact was captured under the label of the “missing money” (Shanker, 2003). This problem created an early debate about the need to improve the energy and reserves price formation versus the approach of creating another mechanism for providing incentives to meet the investment requirements of resource adequacy. An approach adopted in PJM and elsewhere was to create a related but separate capacity market focused on long-term incentives and implemented under the Reliability Pricing Model (RPM) and the related Regional Transmission Expansion Plan (RTEP).

To be clear, short-term operating conditions and long-term investment requirements are related, but notwithstanding the existing long-term adequacy requirements of the reliability rules, something more is needed in order to connect the solution to the missing-money requirement to short-term dispatch operations and actions that maintain minute-by-minute reliability. Although important, the capacity market with RPM and RTEP is not the focus of the present discussion.

In the current PJM framework, the long-term resource adequacy planning requirements are separate from the short-term requirements for operating reserves and other ancillary services. The long-term resource adequacy market innovations do not in themselves deal with the problem of improving the representation of scarcity – and its pricing – in the real-time and day-ahead markets. For example, the existing capacity performance mechanism does provide a scarcity signal for generators but has no corresponding impact on demand or other sources that could substitute for generation at the margin and does not replace the need for the current ORDC or its reform. In order to incent real-time provision of reserves and energy when and where there is scarcity, the value of this additional capacity needs to be included in the energy and reserve prices paid to *all* resources able to respond and reduce the scarcity and paid by *all* loads consuming during these particular intervals of the dispatch. Better scarcity pricing – applied in specific locations and during specific times – will call forth supply and responsive load when and where it is needed, and through the two-settlement system, those who do not respond economically will bear the cost or opportunity cost. Furthermore, the prices for scarcity will be directly tied to the locational and temporal marginal value or marginal cost as determined through the SCED optimization.

The basis for defining consistent scarcity pricing begins with an elementary static model of energy supply and demand. Consider in the first instance a characterization of a single location with energy bids for demand and offers for generation at the variable cost of production. As shown in Figure 1, taken from materials prepared more than two decades ago, market equilibrium occurs at the efficient solution that balances generator supply and load demand and sets the market-clearing price (Hogan, 1993).

Figure 1

During periods of low demand, the equilibrium price is low and the market-clearing price equates the marginal benefit of load with the marginal cost of generation and is equal to the variable cost of production for the marginal plant. As demand increases, represented by a shift in the demand curve to the right, the equilibrium defines a higher market-clearing price, where in the illustration the price that equates marginal benefits and marginal cost is again at the variable cost of generation. Finally, in the highest price case in the illustration, the efficient solution balances supply and demand, but the pricing condition is somewhat different. The efficient price is equal to the marginal benefit of load, but the efficient price is higher than the variable cost of the most expensive generator.

The difference between the efficient price based on marginal conditions in the highest price case, and the variable cost of the last generator, leads to a definition of the scarcity price. The scarcity price appears whenever the available capacity is constrained and at that dispatch level prices rise to clear the market without an accompanying increase in supply. A similar scarcity component would appear on any of the vertical steps of the representation of the generator supply curve.

The illustration is not drawn to scale, and the scarcity component could be very large when the system is operating at its capacity limits. The assumption in the example that supply and demand for energy are at a single location is not important here. The same analysis generalizes to a network with locational marginal pricing to reflect generation costs, marginal losses, and congestion differing across locations. Under the basic pricing principles, scarcity pricing would arise in a natural way and could be an important part of market-clearing prices and settlements to pay for energy.

This basic model of scarcity pricing derives from the principles of economic efficiency and provides a number of benefits. Higher prices during critical periods facilitates dispatch response by transmission connected loads and generation (i.e., resources settled at the ISO's real-time locational prices) when it is most needed. This supports both economic efficiency and system reliability. Additionally, better scarcity pricing would reduce the "missing money" in energy markets and the corresponding challenges of operating good capacity markets and ensuring long-term resource adequacy. All resources providing energy or reserves during scarce conditions would be paid the market-clearing price for the value of their capacity during the scarce intervals. So, for example, instead of PJM paying uplift to resources dispatched at prices of up to \$2000 to alleviate a reserve shortage and recovering the cost through a socialized charge to loads, all resources would be paid the market price for the energy or reserves they provide during scarce intervals, which would be higher due to including a scarcity component.

Better scarcity pricing would improve incentives for dispatchable resources to be available to complement increased supply from intermittent renewable energy. This is because flexible resources needed to balance changing renewable generation would see better price incentives to respond to the changing system needs. And better scarcity pricing would interact with transmission congestion by providing scarcity signals on a locational basis, providing better signals for transmission investment by clearly indicating through significant price separation where transmission investments would be cost-beneficial.

This approach to scarcity pricing would already be in place if the actual market matched the theoretical assumption of complete demand bidding to represent the marginal value of increased load. However, for a variety of reasons, demand bidding has been the exception rather than the rule. In part, the absence of demand bidding is a symptom of the imperfections in the determination of scarcity prices. If prices do not reflect scarcity conditions, there is not as much reason to invest in the flexibility to dispatch load, creating the self-fulfilling prophecy that scarcity will not be well-reflected in the implementation of market pricing. Without significant demand-side bidding, there is currently no market mechanism that will increase prices to indicate exactly where and when there is a potentially very high value for additional capacity.

Better scarcity pricing of energy would go beyond the improvements described above by addressing a closely related challenge in pricing operating reserves, which has received less attention. In fact, the simple energy demand and supply model outlined to introduce the

importance of scarcity pricing is silent on the implications for operating reserves. Better representation of scarcity pricing through ORDC reform would complement increased participation of demand bidding in the dispatch. While the absence of demand bidding makes better scarcity pricing models more important, there is no conflict with improving on both dimensions.

Given the development of the basic energy market design in PJM, better scarcity pricing should be a high priority for enhancing the market design so as to improve the efficiency of the price signal during conditions of scarcity, stimulate more active participation by the demand side of the market, and stimulate efficient investments in supply side resources that can respond quickly to provide more reserves or energy. PJM's current market design does not fully price scarcity at all times because it only values reserves at the NERC-driven minimum reserve requirement plus one step. But in reality, operator actions (with costs greater than the maximum reserve penalty price) are taken to maintain reserves both before the economic dispatch model is run, through biasing, and after, through out of market actions.² These actions skew and depress market price signals. PJM's ORDC reform proposal is designed to better value scarcity and it is, therefore, a much-improved approach to ensure energy and reserves are appropriately valued.

Addressing scarcity through ORDCs requires an expanded discussion that goes beyond the basic static model of energy supply and demand to address multiple reserve types, locations and emergency actions.

Operating Reserve Demand Curve

Operating reserves are an essential element of security-constrained, economic-dispatch although the simple static energy model pushes them into the background. Operating reserves are required in the real dynamic system that the operator must coordinate in order to ensure that the system reliability is maintained in the event of material changes in conditions. A complete dynamic model for the dispatch of energy and operating reserves would incorporate multiple look-ahead periods with continuous adjustment of the actual dispatch and operating reserve schedules to match changing conditions and respect physical constraints such as ramping and transmission limits. Alternatively, if all generation and load could respond instantaneously over their full capacity, then the dynamic dispatch problem could be simplified to a series of static one-period optimizations that would return the discussion to the simple model described for energy supply and demand. Scarcity pricing would arise naturally through demand bidding, and there would be no need to define or maintain operating reserves.

The reality is, however, that generation redispatch can take some time. The typical circumstance is to characterize the ramping rate of generators. This creates interdependencies across periods,

² See Pilog Affidavit.

because the economic dispatch that can be achieved in one period depends on the level of the dispatch in previous periods. It also will take into account constraints on the amount of change needed in the dispatch between successive future periods. Modeling the dynamics of the interdependencies of this period's dispatch on the dispatch in future and later periods is challenging, given the constraints, but there is nothing fundamentally new in the principles of economic dispatch across multiple periods under *known* conditions, and the basic insights of the static model would continue to apply. There would be no separate requirement for operating reserves in the absence of uncertainty and the need to plan for contingencies.

But we do not have perfect foresight: the need for operating reserves arises from the uncertain future supply and demand conditions. The extension of the static model to a dynamic model with known supply and demand conditions, coupled with ramping limits, is conceptually simple. But adding a large element of uncertainty transforms this into a problem with a different degree of complexity. Uncertainty implies that this period's forecast for generation and load balance will not be the same as the actual realized system requirements. Also, the net change in load balance within a dispatch interval may be positive or negative. As a result, the system operator must create some necessary flexibility to be able to ramp up or down as needed to meet the actual load conditions. The need for excess available capacity in any period to ensure reliable system operations defines the operating reserves and related ancillary services that must be set aside to meet the uncertain conditions that unfold.

The expanded optimization could be handled in theory with an appropriate extension of the economic dispatch optimization model. In place of a deterministic optimization across known future conditions, the model would now become a stochastic dynamic optimization model. This is easy to define, but hard to implement. Continuous solution of a full stochastic dynamic optimization model defined over the relevant look-ahead period of immediate concern to the system operator would be beyond present computational capabilities, because of the curse of dimensionality. In each future period multiple "states" could exist, and the number of possible paths through the future grows rapidly like the branches of a decision tree. After very few dispatch periods, the number of possible paths would overwhelm the capabilities of existing software and super computers.

The most immediate evidence of this computational problem is found in the basic formulation of security-constrained economic dispatch. The formulation includes contingency constraints which are defined by credible events that might occur with some non-trivial probability. However, representing the full probability distribution for these events would overwhelm the system dispatch. The compromise has long been to take the conservative position to protect simultaneously against one of these events occurring (the well-known "N-1" condition), without accounting for the complete joint probabilities of one or more contingences at the same time. This is difficult enough, but it is computationally feasible within the requirements of the actual dispatch timing.

The requirement to maintain operating reserves addresses a similar problem of maintaining enough excess capacity and ramping capability to meet the reasonable possible deviations from forecast load and generator outage conditions without resorting to emergency actions up to and including involuntary load curtailment.

The resulting modeling approach is a blend of deterministic and stochastic representation of the supply, demand and system constraints. To illustrate, take the limiting case of a single period, say an hour, where the system operator has a forecast of supply and demand conditions, and a set aside of operating reserves to address the uncertain conditions over the hour. For the moment, the operating reserves are treated as fixed by rule. The operator would choose the economic dispatch ex ante based on the forecast and send instructions to the generators and loads. The ex ante selection of which generators to dispatch for energy and which generators to provide reserves, would be part of a co-optimization problem. Then, as the actual conditions unfold, the available operating reserves would be utilized to address the net deviations from the forecast. This simplified deterministic model utilizes a fixed quantity of operating reserves to address uncertain conditions within the hour.

For this problem, the co-optimization results would determine an implied price of operating reserves. This is conceptually the marginal cost of meeting the last megawatt of the reserve requirement, as measured by the marginal change in the value of the objective function of the ex ante economic dispatch. This implied price would capture the impact of the fixed reserve requirement. However, absent a good representation of scarcity values, such as through demand bidding, this implied reserve price would inherit all the problems of inadequate scarcity pricing, i.e., without demand bidding the price determined from the change in the objective function would not fully reflect the willingness to pay for additional reserve to avoid scarcity. Furthermore, the co-optimization would not capture the benefits of having higher or lower reserves than the fixed requirement.

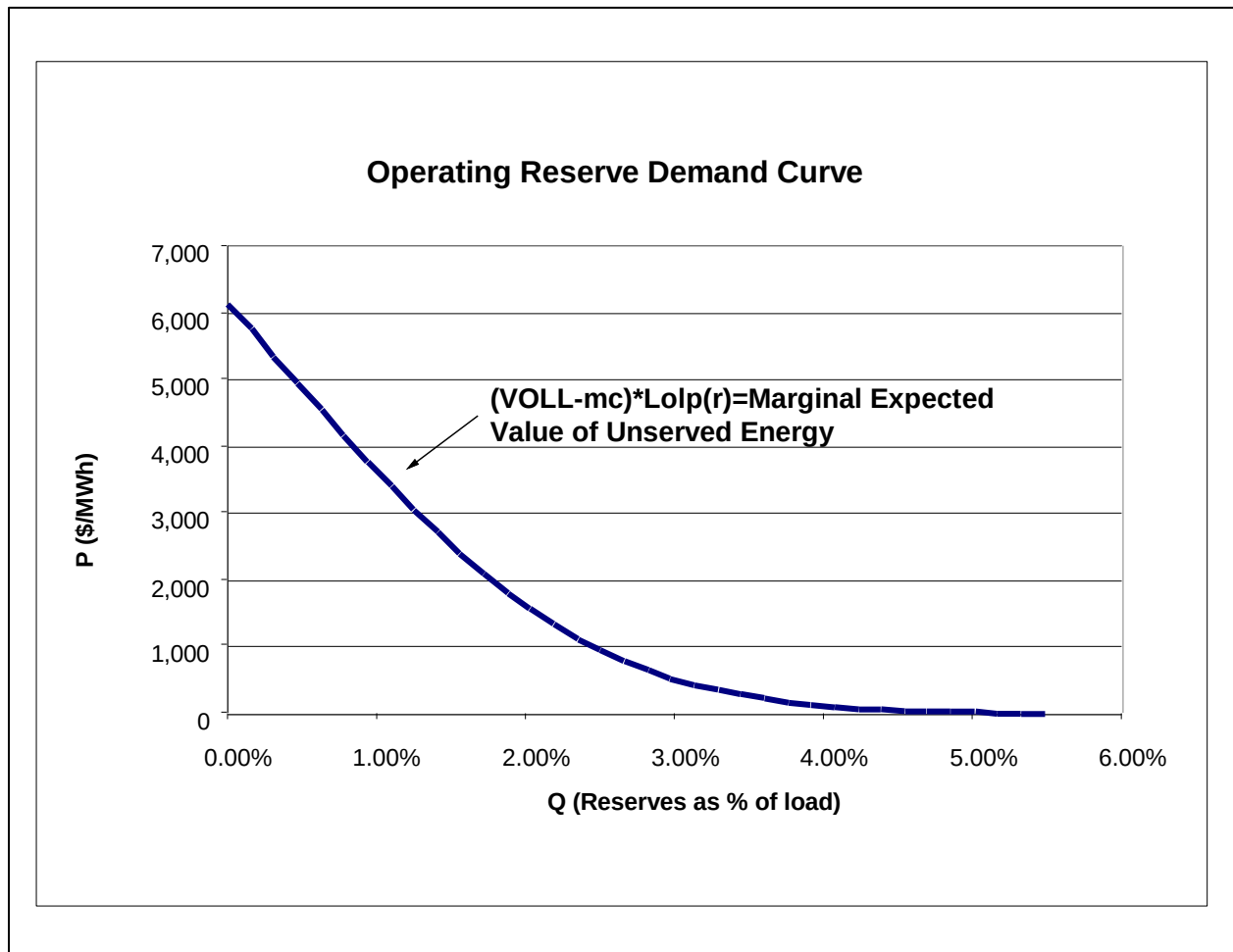
An ORDC arises to proxy for the absence of demand bidding, which as described above has not to this point been sufficiently incentivized to occur naturally in the PJM market. The essential idea of the operating reserve demand curve is to replace the fixed reserve requirement with the variable value of different levels of operating reserves. This is analogous to replacing a fixed load requirement with a bid-in load value in the energy market dispatch.

Operating reserves are a system requirement. They are a product that provides reliability simultaneously to all users of the system. The requirement to procure reserves cannot be efficiently assigned to individual loads or generators, because the need to procure a given megawatt of reserves cannot be attributed to particular market participants. For this reason, operating reserve requirements are determined and applied at the system or zonal level. There is no decentralized mechanism like demand bidding available that would provide a better market solution to efficiently schedule and provide a market-based value for operating reserves. As a result, the demand for

operating reserves is an administrative construct that requires a determination by a central coordinator such as the system operator.

ORDC Structure

In a simple, one period static model with energy and operating reserves, the role of operating reserves suggests a method for approximating the ex ante value of operating reserves of different quantities. Suppose that the ex post choices for the system operator are simply to meet the net change in load through use of the available operating reserves, or to involuntarily curtail load at the cost of the value of lost load (*VOLL*) net of the variable cost of generation at the margin (*mc*). Additionally, suppose the system operator has an estimated distribution of deviations from forecasted net load during actual system operations. With this information it can calculate the loss of load probability for any given level of reserves (*Lolp(r)*). By multiplying by the (*VOLL-mc*), this approach yields the expected cost of marginal load curtailment during actual operation corresponding to any given level of scheduled reserves. In Figure 2 below, the horizontal axis is the quantity of scheduled reserves and the curve shows the estimated incremental value of scheduling additional reserves, given the probability of loss of load. As expected, the value of additional reserves rises as the scheduled quantity falls.

Figure 2

The figure assumes that zero reserves is the reference point at which load curtailment will start to occur. The *VOLL-mc* defines the marginal willingness to pay for an increment of operating reserves at the moment of load curtailment. For this simple model, the product of the $(VOLL-mc)*Lolp(r)$ defines the ORDC, as illustrated in Figure 2 with representative parameter values. This methodology based on the value of lost load and the loss of load probability is familiar from many decades of use in resource adequacy planning studies. The only innovation here is in the use of the probability distribution over the next hour rather than over the much longer horizon of the planning studies. The extension to include minimum contingency reserves (*i.e.*, the Minimum Reserve Requirement) is described in the Appendix.

The formulation of the ORDC described here is conceptual; there are logical variations and enhancements corresponding to differences in how ISOs define the points at which they will curtail load or take emergency actions, as described in more detail below. In particular, PJM is proposing a Penalty Factor based on the maximum cost at which resources could be procured based on market offers, rather than the *VOLL*, as the anchor for its ORDCs. Consistently, the ex post choice implicit

in PJM's ORDC anchor is to invoke operator actions to maintain reserves at or above the MRR at a price of \$2,000, rather than the choice illustrated here, which is to curtail load at a price equal to *VOLL*. Further, the PJM proposal does not subtract the marginal cost of energy from its \$2,000 penalty price in determining the anchor for the ORDC. There are other market rules in PJM which preclude use of any energy offers for price setting that rise above a current system-wide offer cap. This should preclude conditions where including the variable cost of energy in the operating reserve price would cause price rises to or above the *VOLL*. Should this change in the future, the corresponding adjustment of the representation of the scarcity price could be necessary.

PJM's formulation of its ORDCs is consistent with the theory presented here about how the value of incremental reserves will vary with the probability of loss of load during actual operation, but is anchored around PJM-specific assumptions about the actions that will be taken as the level of reserves declines below the MRR.

This simple single period example suggests the basic design criteria for an operating reserve demand curve implementation. To reach a supported result in light of the benefits of – but also the complexities of – stochastic dynamic optimization, it is appropriate to approximate the underlying stochastic dynamic optimization model using a simpler representation of uncertainty. The basic approach is to take the existing practice in defining a deterministic dynamic model with some degree of anticipation of future conditions and optimizing dispatch based on expected values of load and generation in future periods, without explicitly modeling probabilities of different outcomes in future periods. The basic structure of this standard deterministic model is retained but with the addition of an operating reserve demand curve that approximates a current estimate of the future expected value of the use of the reserves. The description should accommodate periods of different lengths and possible multiple emergency actions that could be invoked in response to the realization of net load deviations from the forecast. There could be different reserve types that have different lead times and ramping capabilities.

One design choice will be the selection of the degree to look forward in describing the uncertainty applicable in estimating the value of operating reserves. To illustrate, suppose we take the simple single period model with a one hour forward look for both the deterministic energy dispatch forecast and the period of uncertainty to be met with operating reserves. Now suppose that the actual practice is to use this model on a rolling basis to update the forecast used for the dispatch based on new information, say every five minutes. The rolling update for the forecast and deterministic optimization still looks one hour ahead. But we know that after the next five-minute interval we will update this forecast and the optimization.

How should this affect the look-ahead period for the uncertainty that applies to the operating reserve loss of load probability calculation? One suggestion might be that the uncertain period should now be matched to the five-minute period, recognizing that the operator can change both the dispatch and the selection of reserves at the start of the next five-minute interval. Although

appealing, this approach would understate the importance of uncertainty and undervalue operating reserves.

Recall that the intent is to approximate prices that would capture the value in the full stochastic dynamic optimization model. This expanded modeling framework would attribute two different sources of value for operating reserves. First would be the reserves needed to meet the uncertainty in the first five-minute interval. The second element would be the value at the end of the five-minute interval for the remaining unused reserves to meet the commitments in all future intervals. The shorter the dispatch interval, the less important would be the uncertainty in the immediate interval and more would be contributed by the future value of reserves.

However, the computational barrier of the full stochastic dynamic model extends to the estimation of the value of reserves for all future periods. Hence, the actual implementation cannot depend on calculating this elusive estimate. The outline of the ORDC relies on calculation of the contribution in the relevant look-ahead interval, and implicitly assumes that the future value of the remaining reserves is effectively zero. This implies that the horizon for the uncertainty estimation should be long enough to make the residual value close to zero. This modeling requirement provides that the period selected for the estimation of the *Lolp* used in the ORDC approximation need not, and probably should not, be the same as the dispatch interval in the rolling update of the ex ante dispatch. For instance, a reasonable choice would be to have a rolling five-minute dispatch interval, with a multi-period look ahead, with each included ORDC obtained from an estimate of the uncertainty over the next hour.

PJM proposes to base its ORDC reforms on a 30-minute look ahead for uncertainty for the Synchronized and Primary Reserve Requirements and a 60-minute look ahead for the 30-Minute Reserve Requirement. This approach is a reasonable way to account for the uncertainty in estimating the value of operating reserves because it appropriately accounts for the multi-period nature of forecast uncertainties.

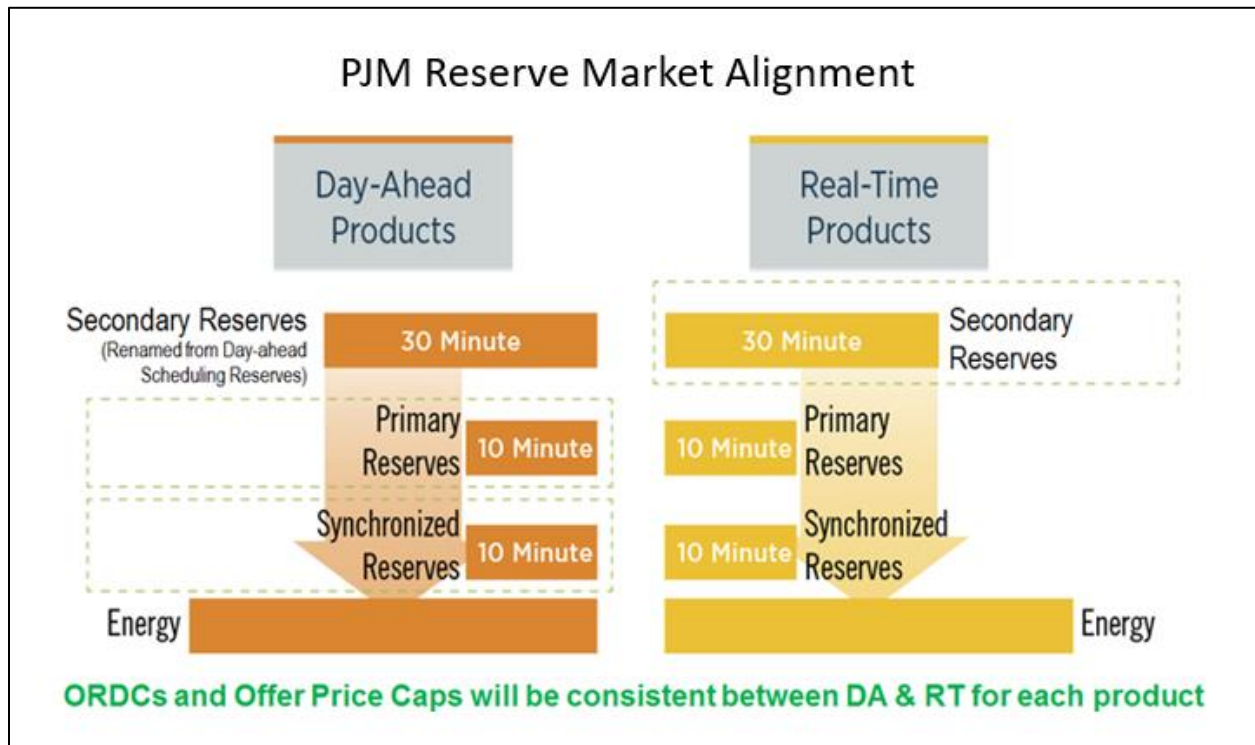
Multiple Reserve Products

The basic ORDC design can accommodate multiple reserve products. The typical distinctions among types of operating reserves are based on the response time before the reserves would be available. Some reserve capability is always available, such as the capacity set aside for frequency regulation. This total regulating capacity is relatively small and must be maintained to address the need for continuous adjustments to maintain system balance and operations within set frequency tolerances. This frequency regulation capacity is not the focus of the present discussion.

In the proposed PJM design, as summarized in Figure 3, there will be three categories of operating reserve requirements denoted as “Synchronized”, “Primary”, and “30-Minute” reserves. These reserve capacities cascade. For example, Primary Reserve can also meet all the conditions that can be addressed by the 30-minute Reserves, but the reverse is not true. Hence, the price of Primary Reserve will always be at least as large as the price for 30-minute Reserve. The reserve

prices in the proposed PJM model include minimum reserve requirements, penalty factors for falling below these minimums, and loss-of-load type calculations for the probability of falling below these minimums. The details for the resulting reserve products and prices are provided in the Appendix.

Figure 3



The deterministic dispatch interval for the rolling PJM economic dispatch is 5 minutes. As discussed above, this is different than the period used to set the relevant probability distribution for the uncertainty applied in valuing the operating reserves. The PJM plan can be described as a one-hour interval to determine the full range of the distribution of deviations from the expected net load. For the first half of that period, the 30-minute uncertainty applies only to the valuation of two types of 10-minute reserves. For the second half of the period, the full one-hour uncertainty applies to the combined levels of 10-minute and 30-minute reserves. The combination of uncertainties would define an ORDC that would be applied to each five minutes in the deterministic dispatch.

These modeling choices are reasonable and are consistent with similar applications in other organized markets (Hogan and Pope, 2017). The result would be a rolling dispatch of energy and reserves, co-optimizing the level and choice of generators to provide energy and those to provide reserves. Non-generator sourced reserves, such as through demand response, can be included as well. The corresponding prices for energy and reserves would be internally consistent and would reflect the scarcity value of reserves as expressed in the ORDC.

The results of the PJM approach are similar to those that would be obtained with full demand bidding of flexible load every five minutes assuming that the estimated scarcity price corresponds to the bids the loads would make and the PJM approach is, therefore, sound. Furthermore, there would be no change in the dispatch model design required to allow for the entry of more demand bidding because the co-optimization would take into account any price-sensitive demand when determining the optimal level of reserves at prices that respected the price-sensitive demand bids.

Defining and Valuing Emergency Response

System operators employ a number of actions to address imbalance problems when net load (i.e., load less generation) deviates from the dispatch forecast. These range from calls for voluntary load reductions to temporary voltage reductions and, as a last resort, involuntary load curtailments through rotating blackouts. The basic model for valuing operating reserves illustrated in Figure 2 illustrates the logic and the connection to only one action, which is to the curtailment of load

The extension to include a sequence of increasingly costly emergency actions would replace the single estimate of the *VOLL* with a series of emergency actions. Each action is available over a limited range and has an associated cost. The actions would be ordered according to increasing cost. Now the single estimate of the loss of load probability extends to an estimate of the probability that the net load change falls within the appropriate range for each emergency action. The implied value of an increment of operating reserves is the sum of the expected cost of the avoided emergency actions.

Although the refinements for multiple emergency actions are straightforward, the impact on the estimate of the ORDC over the range above the level requiring emergency actions may not be very large. Furthermore, there is a trade-off between representing the cost of the individual emergency actions and the range for the net load change that triggers the action. An example and further details on the treatment of the emergency actions are provided in the Appendix.

Analysis can support the selection of values for the various emergency actions. A guiding principle should be to set values and implied prices to reflect the actual choices of the economic dispatch as set by the system operator. However, the identification of a few representative emergency actions and their associated values also presents policy choices.

The focus is on the demand curve representing the willingness to pay to avoid the respective emergency actions. This demand perspective and the avoided cost is distinct from the cost of actions necessary to avoid a need to invoke the emergency action. The principal cost of alternatives is in the opportunity cost of providing the operating reserves, and this cost is already reflected in the generator supply offers. But in constrained situations, the measure of the cost of supply and the value of demand differ by the value of scarcity. The values needed for the ORDC are those that define the willingness to pay to avoid the emergency action.

This general perspective still leaves important choices. For example, in the case of involuntary load curtailment, the *VOLL* represents the appropriate concept to guide the decision. However, empirical studies will provide only a little guidance as to which value is appropriate across a range of estimates. The choice will depend in part on the actual curtailment policy applied by the system operator. For example, a rolling blackout will have priorities to exclude certain loads, such as for hospitals or other emergency facilities. For those who are curtailed, the relevant value for ORDC construction would be the average value of lost load for all those included, not the implied higher *VOLL* for those that would not be curtailed.

Similar issues would apply in defining other emergency actions. The balance between detail and workable approximations will be a choice. As discussed in the Appendix, in many cases it would be reasonable to aggregate the emergency actions into a small number of groups or have only one to serve as a representative proxy.

The choice in the PJM reform proposal is to employ the revised penalty factors, motivated by an objective to ensure that the individual penalties approximate at least the various costs of the emergency actions. In addition, the PJM proposal includes a cascade model that aggregates these penalty factors to produce higher operating reserve prices. With very low reserves the resulting prices would be within the range of reasonable estimates of the value of loss load (OFGEM, 2014) (Potomac Economics, 2017). The details appear in the Appendix.

Implementing an ORDC

The details of a workable computational implementation of an ORDC depend in part on the characteristics of the optimization model formulated for the bid-based, security-constrained, economic dispatch. The direct approach would be to emulate the treatment of bid-in load, where the price of the load varies with the quantity dispatched.

The price for the ORDC would be calculated as above to reflect the estimated probabilities of the changes in net load and the costs of emergency action. In principle, the scarcity component would be the marginal cost of the avoided emergency actions net of the energy cost saving from the dispatch. In most cases, this energy cost saving adjustment would be small relative to the cost of emergency actions. However, in circumstances where the variable cost of the marginal generator is close to the cost of emergency actions, the scarcity value should reflect the adjustment to ensure that the implied price of energy does not exceed the estimated costs of the emergency actions.

The basic model of the integrated real-time ORDC takes the commitment of units and related operator actions as given and independent of the scarcity conditions. In real systems, the system operator may take actions that bias the inputs into the dispatch model or after-the-fact through out-of-market (OOM) actions, for example to ensure reliability conditions that are not well represented in the dispatch model. These reliability commitments would have the effect of increasing the available system capacity and, therefore, increasing the estimated level of operating reserves.

Without some adjustment for OOM decisions, the implication would be that scarcity conditions could trigger OOM actions which in turn produce lower scarcity values for a given level of operating reserves, and therefore lower market prices. This unintended consequence should be mitigated by recognizing that the OOM actions imply a decision to pay for higher reserve requirements. The essence of the adjustment to offset the price impact of the OOM action would be to shift the ORDC by an amount that proxies for the change in capacity induced by the operator actions.

This integration of a system-wide ORDC which is carried through PJM's proposal allows for the simultaneous optimization of bid-in load, offered generation, and operating reserves. The price of operating reserve will be determined by the value from the ORDC and the tradeoff with the dispatch of generation and load. The price of energy will be the variable cost of the marginal generator plus the implied scarcity value of the generating capacity derived from the price of operating reserves.

The dispatch model can have multiple periods with a rolling update of the energy and reserve dispatch and the associated prices. In this formulation, the approximation of the underlying stochastic model employs the forecast of net load over the look-ahead horizon, and incorporates the expected marginal value represented by the penalty factors for the use of emergency actions across the range of the estimated probability distribution of the net load change over the look-ahead period.

The result is an economic dispatch model with the same deterministic structure as current dispatch models, with nothing more than the addition of the modeling equivalent of one more load subject to flexible dispatch. The incremental computational requirements would be de minimis.

Locational ORDC Design

A system-wide ORDC assumes that the location of operating reserves is not a constraint. Given the importance of transmission constraints in the basic energy dispatch, this may appear as a contradiction. The resolution of the apparent conflict rests on a characterization of transmission constraints as applied to the dispatch of energy and scheduling of reserves.

A simple approach would be to characterize the constraints under the assumption that the forecast load, generation and transmission conditions never changed. Then the economic dispatch would have the same steady-state power flows over an extended period of time. These sustained flows would face transmission limits on the ability to maintain the flows. For example, thermal limits and line sag do not happen instantaneously, but can be material limits on sustained power flows. In effect, therefore, the usual transmission limits are soft constraints in that they apply most directly to steady state conditions.

The time dependence of transmission constraints appears in the N-1 contingency limits for security constraints. Typically, the transmission power flow models are the same for the contingency

conditions, but the transmission limits are higher to reflect the fact that the post-contingency flows will be active only for a limited period before the system is fully restored to normal steady-state operating conditions.

The implicit assumption in a single system-wide ORDC is that the level and period of deployment of operating reserves will be limited enough to ensure that transmission constraints need not inhibit the use of the reserves when needed.

However, there may be limits on the ability to match locational deviations in net load and the deployment of operating reserves. In effect, there could be transmission limits on the deployment of reserves. The same power flow models (i.e., lines and nodes) would govern for any given realization of the geographic dispersion of deviations in net load, but the power flow would be different in each realization. The full power flow description could be included in principle in a stochastic dynamic programming model, but this approach is computationally infeasible at present.

To remain within the deterministic framework of the existing economic dispatch optimization formats (i.e., the optimization does not explicitly consider the probabilities of different future outcomes), another approach that relies more on expected value formulations is required. Borrowing from the long experience with planning models, such as in the PJM RTEP process, the use of a zonal representation of reserve location and interface transmission limits is a feasible approach that would capture the main outlines of locational operating reserve demand curves.

Based on external analysis and simulation, the zonal approach assumes that the system operator can define nested operating reserve regions separated by a closed interface. Consider the case of the total system and one nested zone. The short-term energy transfer limit across the interface from the rest of the system to the nested zone would be a policy choice based on the external analysis. The probability distributions for net load change would be estimated for the rest of the system and for the nested zone. Since these distributions apply to the deviations from the respective forecast, independence of these distributions of forecast deviations is a simplifying but reasonable assumption.

In addition, the emergency actions that would apply in the nested zone and for the rest of the optimal dispatch of operating reserves would imply demand curves with a simple form reflecting the best use of the available reserves inside and outside of the nested zones and the interface limits. For any given realization of the net load deviation, the cost of the emergency action is assumed to be lower outside the nested zone. The cost of emergency actions outside of the nested zone applies within the nested zone up to the megawatt limit equal to the available interface capacity net of the scheduled flow from the ex ante energy dispatch. For incremental reserves within the nested zone above this amount, the more expensive emergency actions within the nested zone enter the optimal reserve schedules and determine the price of incremental reserves within the nested zone.

These rules apply for each realization of the deviation in net load. In the case of a single representation of emergency actions in each region, a corresponding probability tree allows direct calculation of the marginal value of the two types of reserves and of the interface capacity. The tree also determines the probability of the marginal values, which allows direct calculation of the expected marginal value and defines the three-element operating reserve demand curve for reserves inside and outside the constrained zone and the interface capacity. The details appear in the Appendix.

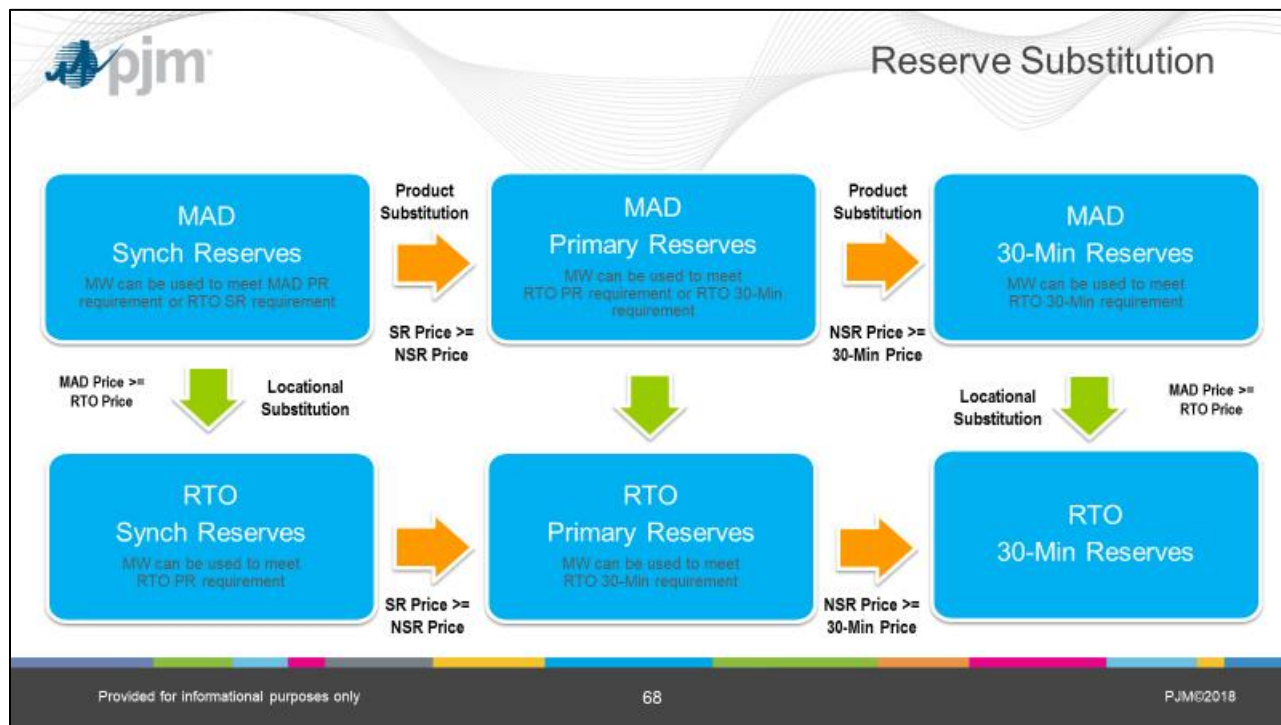
The interaction of reserves in the different regions creates a three-dimensional operating reserve demand curve interacting with load and generation in the dispatch to determine the clearing price of reserves inside of the zone, outside of the zone, and for the interface constraint. This would be similar to the conditions that would arise if bids were accepted for loads where the implied price for each load depended on the dispatch of related loads. Although possible in principle, this is not the normal assumption in existing economic dispatch models, where load bids are separable.

To maintain the goal of working within the framework of existing dispatch models, implementation of the locational ORDC must impose a separability condition, where the values are additive. One approach would set a benchmark estimate of the two levels of reserves and the interface capacity. For example, use of the co-optimized solution from the previous dispatch interval to serve as the benchmark for the current dispatch interval. Then varying each quantity, while holding the others fixed, would yield a separable set of three demand curves. This could be accepted as a workable approximation of the values from the multi-dimensional ORDC. These curves could be incorporated in the economic dispatch model in the same ways as described for the single ORDC.

If needed, this framework also would provide the information required to update the benchmark and converge to a combined solution that yields a consistent solution for the ORDC zonal prices. The co-optimization in the dispatch model includes the use of the interface limit for energy and the set aside for reserve deployment. All this would combine with the usual locational prices of energy. The details are in the Appendix.

The PJM proposed approach applies a similar but distinct approach in characterizing locational interactions. Suppose the immediate case, as shown in Figure 4, in which the Mid-Atlantic Dominion (MAD) region is constrained. The result recognizes six reserve products, the three types of real-time reserves in each of the MAD and the entire Regional Transmission Organization (RTO). The cascade model now has MAD reserves affecting the price in the RTO, but the RTO reserves do not affect the incremental price in the constrained MAD region.

Figure 4



The same approach would apply to any constrained zones. The principal simplification is to treat the entire market as a single zone, and then to represent the effects inside each constrained zone as additive to the impacts and prices for the entire region. By assuming this cascade model and additivity across locations, the PJM approach does not reflect interactions between the reserves in different regions, but has the advantage of greater simplicity in implementation. The results are illustrated in the detailed example in the Appendix.

Market Power and ORDC Pricing

A central problem in regulating power markets has been the concern with generators exercising market power. When a generator can control multiple facilities, or has related financial interests, it can manipulate price by withholding supply. The loss on its reduced production is more than made up by the increase in price received for the output from remaining units and from settlements on related financial interests. This market power can be implemented through physical withholding, by removing the plants from dispatch, or economic withholding, by increasing the plant's offer price.

Physical withholding can be addressed by must-offer requirements. More controversial has been the policy of setting accompanying offer caps to foreclose economic withholding. It is difficult to distinguish between legitimate high-cost offers and the exercise of market power. The difficulties have been compounded by the faulty assumption that higher market-clearing prices, needed to reflect scarcity and provide better incentives in operations, require high energy offers from

generators. The resulting dilemma has been how to separately identify price increases resulting from scarcity from the exercise of market power.

The ORDC substantially mitigates this problem of identifying economic withholding by providing a clear distinction between a scarcity price, from the ORDC, and energy offers that reflect variable generation costs. Under conditions of reserve scarcity, when operating reserves are reduced, low energy offers can be fully compatible with high market-clearing prices, for example because the generators on line and providing energy have limited ability to ramp quickly. Reserves are limited and the ORDC produces a high scarcity price. This scarcity component adds to the variable cost of energy and produces a high market-clearing price for energy. Hence, generators do not need to inflate their variable offers in order to achieve higher prices reflecting the scarcity value of their capacity. Generous offer caps would prevent material exercise of market power through economic withholding without creating a conflict for the ORDC. Likewise, if needed, offer caps could be provided for operating reserves as well as for energy. Hence an ORDC reduces the cost of using offer caps to mitigate generator market power. This is a natural and beneficial feature of the PJM ORDC reform proposal.

Day-Ahead and Real-Time ORDC

The basic outline for an ORDC describes the design and implementation challenges within the framework of economic dispatch. The essential design elements apply both to the real-time and to day-ahead markets with a two-settlement system. As always, a general objective is to maintain consistency between the real-time design and the day-ahead design.

Consistency requires that the day-ahead representation of the ORDC reflects the uncertainty regarding the net load deviations from the forecast dispatch. The uncertainty regarding these deviations, and the short-lead times required of operating reserves, give rise to the estimated value of incremental reserves. This real-time deviation is not the same as the uncertainty between the day-ahead forecasts and real-time outcomes. The day-ahead dispatch will face both types of uncertainty.

The variation between day-ahead and real-time is important, but different from the real-time uncertainty. The treatment of this uncertainty depends on the availability of generation capacity and the timing of its commitment. If all the capacity were available for the real-time dispatch, and required no day-ahead commitment decision, then the uncertainty around the day-ahead forecast would be handled through the rolling change in the dispatch updated over the day. By contrast, since some relevant generating facilities must be committed day-ahead in order to be available for the real-time dispatch, the circumstance is analogous to the real-time problem of setting operating reserves as part of the real-time dispatch before the actual conditions are known.

The form of the day-ahead ORDC follows the same model as the real-time ORDC. The principal issue is the treatment of the day-ahead uncertainty. The details are in the Appendix in the discussion of day-ahead and real-time ORDCs.

The day-ahead settlements will be for energy and reserves. The resulting forward contracts create a financial obligation that can be met by providing the physical counterpart (generation injection, load withdrawal or operating reserve schedule) in the real-time dispatch or paying the associated market-clearing price in the real-time dispatch.

As discussed in the Appendix, the basic model for the day-ahead includes virtual transactions for both energy and reserves. Virtual bids and offers support price convergence by eliminating arbitrage opportunities between markets. In addition, with exact replication of the physical generator offers as in real-time, virtual transactions for energy and reserves can be shown to achieve full consistent equilibrium between day-ahead and the real-time dispatch and prices. See the Appendix for further details for the settlement of the operating reserve requirements.

The PJM proposal does not anticipate including virtual reserve products, but there will be virtual energy products and energy price arbitrage. The main impact of not including virtual reserve products should be to substitute “physical” reserves for virtual reserves. As always, the day-ahead reserve contracts will be settled against the real-time prices for reserves.

Summary

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. Any approach to valuation of operating reserves, embedded within the framework of existing dispatch models, entails approximations. Economic connections between the value of emergency actions, including the value of loss of load, the probability distribution for changes in reserve requirements, and the interaction across constrained reserve zones provide a framework based on first principles and a guide to the development of implementable approximations of the interacting multiple product operating reserve demand curves. The PJM proposal moves far in this direction and the framework provides a guide for future enhancements.

Appendix: Formulation and Computation of Reserve Scarcity Prices through Operating Reserve Demand Curves

A representation of the value of operating reserves is essential for establishing prices for energy and reserves. This Appendix, adapted from (Hogan and Pope, 2017), provides further detail on the elements in the structure of an operating reserve demand curve based on first principles. The ORDC illustrated here provides an approximation of the value of operating reserves appropriate for inclusion in a single period representation of a dispatch model.

The full co-optimization framework, simultaneously considering both the multi-period dispatch of energy and reserves to meet forecast load conditions, could be important for some extensions of the ORDC.

Economic Dispatch and Operating Reserves

The assumption of the existence of an operating reserve demand curve simplifies the analysis. The demand curve gives rise to a reserve benefit function that can be included in the objective function for economic dispatch. The basic framework approximates the complex problem with a wide range of uncertainties and applies a pricing logic to match the actions of system operators. The main features include:

- **Single Period Model.** There is a static representation of the underlying dynamic problem. This static formulation is a conventional building block for a multi-period framework.
- **Deterministic Representation.** The single period dispatch formulation is based on bids, offers, and expected network conditions as in standard economic dispatch models. The operating reserve demand curve represents the value of uncertain uses of reserves without explicitly representing the uncertainty in the optimization model.
- **Security Constrained.** The economic dispatch model includes the usual formulation of N-1 contingency constraints to preclude cascading failures.
- **Ex-Ante Dispatch.** The dispatch is determined before uncertainty about net load relative to forecast is revealed.
- **Expected Value for Reserves.** The reserve benefit function represents the expected value of avoiding involuntary load curtailments and similar emergency actions.
- **Multiple Reserve Types.** The model of the operating reserve demand allows for a typical cascade model of different reserve types. Online spinning reserves and fast start standby reserves interact to provide complementary reserve prices.
- **Administrative Balancing.** Subsequent uncertain events are treated according to administrative rules to utilize operating reserves to maintain system balance and minimize load curtailments.
- **Consistent Prices.** The model co-optimizes the dispatch of energy and reserves and produces a consistent set of prices for the period.

The framework allows for a variety of implementations with multiple zones, forward markets and other common aspects of electricity markets.

Modeling Co-Optimized Economic Dispatch with Operating Reserves

The model presented below is a one-period “DC-load” model with co-optimization of reserves and energy. The notion is that the dispatch set at the beginning of the period must include some operating reserves that could deal with subsequent uncertain events. The emphasis is on the co-optimization of energy and reserves to illustrate the major interactions with energy prices. The initial approach assumes no locational constraints on reserves. The initial, simplified example assumes the existence of a separable non-locational benefit function for reserves.

Here the various variables and functions include:

d : Vector of locational demands

g_R : Vector of locational responsive generation

r_R : Vector of locational responsive reserves

r_{NS} : Vector of locational non-spin reserves

r_R^0 : Aggregate responsive reserves

r_{NS}^0 : Aggregate non-spin reserves

g_{NR} : Vector of locational generation not providing reserves

$B(d)$: Benefit function for demand

$C_k(g_k)$: Cost function for generation offers

K_k : Generation Capacity

$R_k(r_k)$: Reserve value function integrating demand curves

$r_k^{\max}$: Maximum Ramp Rate

H, b : Transmission Constraint Parameters

i : Vector of ones.

Assuming that unit commitment is determined, the stylized economic dispatch model is:

$$\begin{aligned}
 (1) \quad & \underset{d, g_R, g_{NR}, r_R^0, r_{NR}^0, r_{NS}^0, r_{NS}^0 \geq 0; \hat{y}}{\text{Max}} \quad B(d) - C_R(g_R) - C_{NR}(g_{NR}) + R_I(r_R^0) + R_{II}(r_{NS}^0) \\
 & d - g_R - g_{NR} = \hat{y} \quad \text{Net Loads} \quad \rho \\
 & i^t \hat{y} = 0 \quad \text{Load Balance} \quad \lambda \\
 & H\hat{y} \leq b \quad \text{Transmission Limits} \quad \mu \\
 & g_R + r_R \leq K_R \quad \text{Responsive Capacity} \quad \theta_R \\
 & g_{NR} \leq K_{NR} \quad \text{Generation Only Capacity} \quad \theta_{NR} \\
 & r_{NS} \leq K_{NS} \quad \text{Non-Spin Capacity} \quad \theta_{NS} \\
 & i^t r_R = r_R^0 \quad \text{Responsive Reserves} \quad \gamma_R \\
 & i^t r_R + i^t r_{NS} = r_{NS}^0 \quad \text{Non-Spin Reserves} \quad \gamma_{NS} \\
 & r_R \leq r_R^{\max} \quad \text{Responsive Ramp Limit} \quad \eta_R \\
 & r_{NS} \leq r_{NS}^{\max} \quad \text{Non-Spin Ramp Limit} \quad \eta_{NS}.
 \end{aligned}$$

This formulation assumes that the non-spinning reserve generators are not spinning and, therefore, cannot provide energy for the dispatch. The Non-Spinning Reserve equation implements a cascaded model for reserves, where both responsive and non-spinning reserves contribute to the aggregate non-spinning supply. The cost for reserves is the opportunity cost in the tradeoff for providing energy.

For the present discussion, the pricing relationships follow from the usual interpretation of a convex economic dispatch model. This could be expanded to include unit commitment and extended LMP formulations (ELMP), but the basic insights would be similar (Gribik, Hogan and Pope, 2007).

An interpretation of the prices follows from analysis of the dual variables and the complementarity conditions. For an interior solution, the locational prices (ρ) are equal to the demand prices for load.

$$(2) \quad \rho = \nabla B(d).$$

The same locational prices connect to the system lambda and the cost of congestion for the binding transmission constraints in the usual way.

$$(3) \quad \rho = \lambda i + \mu^t H.$$

In addition, the locational prices equate with the marginal cost of generation plus the cost of scarcity.

$$(4) \quad \rho = \nabla C_R(g_R) + \theta_R.$$

A similar relation applies for the value of non-reserve related generation.

$$(5) \quad \rho = \nabla C_{NR}(g_{NR}) + \theta_{NR}.$$

The marginal value of responsive reserves connects to the scarcity costs of capacity and ramping limits.

$$(6) \quad \theta_R + \eta_R = \gamma_R i + \gamma_{NS} i = \frac{dR_I(r_R^0)}{dr} i + \frac{dR_{II}(r_{NS}^0)}{dr} i.$$

The corresponding marginal value of non-spinning reserves reflects the scarcity value for capacity and ramping limits.

$$(7) \quad \theta_{NS} + \eta_{NS} = \gamma_{NS} i = \frac{dR_{II}(r_{NS}^0)}{dr} i.$$

If there are no binding ramp limits for responsive reserves, then $\eta_R = 0$ and from (6) we have θ_R as a vector where every element is the price of responsive reserves. Similarly, for the ramping limits on non-spinning reserves, if these are not binding, then $\eta_{NS} = 0$ and from (7) we have θ_{NS} as a vector where every element is the price of non-spinning reserves.

Approximate Operating Reserve Demand Curve in a Co-optimized System

This co-optimization model captures the principal interaction between energy offers and scarcity value. The assumption of a benefit function, $R(r)$, for reserves simplifies the analysis. Here, a derivation of a possible reserve benefit function provides a background for describing the form of an ORDC. To simplify the presentation, focus on the role of one class of responsive reserves only. And consider only an aggregate requirement for reserves with no locational constraints.

To the various variables and functions add:

$f(x)$: Probability for net load change equal to x .

Again, for purposes of designing the ORDC take that unit commitment as given. The stylized economic dispatch model includes an explicit description of the expected value of the use of reserves. For the reserves here, only aggregate load matters. This reserve description allows for a one-dimensional change in aggregate net load, x , and an asymmetric response where positive net load changes are costly and met with reserves and negative changes in net load are ignored. This model is too difficult to implement but it provides an interpretation of a set of assumptions that leads to an approximate ORDC. Here we first ignore minimum reserve requirements to focus on the expected cost of the reserve dispatch.

The central formulation treats net load change x and use of reserve, δ_x , to avoid involuntary curtailment. This produces a benefit minus cost of $VOLL \cdot (i^t \delta_x) - (C_R(g_R + \delta_x) - C_R(g_R))$ and

this is weighted by the probability $f(x)$. This term enters the objective function summed for all non-negative values of x . The basic formulation includes:

$$\begin{aligned}
 (8) \quad & \underset{d, g_R, g_{NR}, r_R, \delta_x \geq 0; \hat{y}}{\text{Max}} \quad B(d) - C_R(g_R) - C_{NR}(g_{NR}) + \sum_{x \geq 0} \left(\text{VOLL} i^t \delta_x - (C_R(g_R + \delta_x) - C_R(g_R)) \right) f(x) \\
 & d - g_R - g_{NR} = \hat{y} \quad \text{Net Loads} \quad \rho \\
 & i^t \hat{y} = 0 \quad \text{Load Balance} \quad \lambda \\
 & H\hat{y} \leq b \quad \text{Transmission Limits} \quad \mu \\
 & g_R + r_R \leq K_R \quad \text{Responsive Capacity} \quad \theta_R \\
 & i^t \delta_x \leq x, \forall x \quad \text{Responsive Utilization} \quad \gamma_x \\
 & \delta_x \leq r_R, \forall x \quad \text{Responsive Limit} \quad \varphi_x \\
 & g_{NR} \leq K_{NR} \quad \text{Generation Only Capacity} \quad \theta_{NR}.
 \end{aligned}$$

This model accounts for all the uncertain net load changes weighted by the probability of the outcome, and allows for the optimal utilization of reserve dispatch in each instance.

To approach the assessment of how to approximate reserves with a common scarcity price across the system, further simplify this basic problem.

1. Treat the utilization of reserves δ_x as a one-dimensional aggregate variable.
2. Replace the responsive reserve limit vector with a corresponding aggregate constraint on total reserves.
3. Utilize an approximation of the cost function, $\hat{C}$, for the aggregate utilization of reserves, and further approximate the change in costs with the derivative of cost times the utilization of reserves.

This set of assumptions produces a representation for the use of a single aggregate level of reserves for the system:

$$\begin{aligned}
 (9) \quad & \underset{d, g_R, g_{NR}, r_R, \delta_x \geq 0; \hat{y}}{\text{Max}} \quad B(d) - C_R(g_R) - C_{NR}(g_{NR}) + \sum_{x \geq 0} \left(\text{VOLL} \delta_x - \partial \hat{C}_R(i^t g_R) \delta_x \right) f(x) \\
 & d - g_R - g_{NR} = \hat{y} \quad \text{Net Loads} \quad \rho \\
 & i^t \hat{y} = 0 \quad \text{Load Balance} \quad \lambda \\
 & H\hat{y} \leq b \quad \text{Transmission Limits} \quad \mu \\
 & g_R + r_R \leq K_R \quad \text{Responsive Capacity} \quad \theta_R \\
 & \delta_x \leq x, \forall x \quad \text{Responsive Utilization} \quad \gamma_x \\
 & \delta_x \leq i^t r_R, \forall x \quad \text{Responsive Limit} \quad \varphi_x \\
 & 0 \leq r_R, \quad \text{Explicit Sign Constraint} \quad \omega_R \\
 & g_{NR} \leq K_{NR} \quad \text{Generation Only Capacity} \quad \theta_{NR}.
 \end{aligned}$$

This formulation provides a reasonably transparent interpretation of the implied prices. Focusing on an interior solution for all the variables except r_R , we would have locational prices related to the marginal benefits of load:

$$(10) \quad \rho = \nabla B(d).$$

The same locational prices connect to the system lambda and the cost of congestion for the binding transmission constraints.

$$(11) \quad \rho = \lambda i + H^t \mu.$$

The locational prices equate with the marginal cost of generation-only plus the cost of scarcity when this generation is at capacity, which appears in the usual form.

$$(12) \quad \rho = \nabla C_{NR}(g_{NR}) + \theta_{NR}.$$

The locational prices equate with the marginal cost of responsive generation and display the impact of reserve scarcity. First, the impact of changing the base dispatch of responsive generation implies:

$$\rho = \nabla C_R(g_R) + \sum_{x \geq 0} \left(\partial^2 \hat{C}_R(i^t g_R) \delta_x i \right) f(x) + \theta_R.$$

The second-order term captures the effect of the base dispatch of responsive generation on the expected cost of meeting the reserves due to deviation in net load leading to δ_x in reserves being needed. This term is likely to be small. For example, if we assume that the derivative $\partial \hat{C}_R$ is constant, then the second order term is zero.

When we account for the base dispatch of reserves, we have:

$$\theta_R = \sum_{x \geq 0} \varphi_x i + \omega_R.$$

When accounting for utilization of the reserves, we have:

$$\gamma_x + \varphi_x = \left(VOLL - \partial \hat{C}_R(i^t g_R) \right) f(x).$$

Let $r = i^t r_R$. Then for $x \leq r$, $\varphi_x = 0$; $x \geq r$, $\gamma_x = 0$. Hence,

$$\theta_R = \sum_{x \geq r} \varphi_x i + \omega_R = \left(VOLL - \partial \hat{C}_R(i^t g_R) \right) (1 - F(r)) i + \omega_R.$$

Combining these, we can rewrite the locational price as:

$$(13) \quad \rho = \nabla C_R(g_R) + \sum_{x \geq 0} \left(\partial^2 \hat{C}_R(i^t g_R) i \delta_x \right) f(x) + \left(VOLL - \partial \hat{C}_R(i^t g_R) \right) (1 - F(r)) i + \omega_R.$$

Equations (9) through (13) capture our approximating model for aggregate responsive reserves. Here $Lolp(r) \equiv 1 - F(r)$, the loss of load probability given reserve r .

The term $(VOLL - \partial \hat{C}_R(i^t g_R))(1 - F(r))$ in (13) is the scarcity price of the ORDC. If the second order terms in (13) are dropped, then the scarcity price is the only change from the conventional generation-only model. In practice, we would have to update this model to account for minimum reserve levels, non-spin, and so on, and include an estimate of $\bar{c} \approx \partial \hat{C}_R$ in defining the net value of operating reserves $v \approx VOLL - \bar{c}$.

Note that under these assumptions the scarcity price is set according to the opportunity cost of using generation for reserves rather than the increasing cost to produce energy, i.e., using $\hat{C}$ for the marginal responsive generator in the base dispatch. Depending on the accuracy of the estimate in $\hat{C}$, this seeks to maintain that the energy price plus scarcity price never exceeds the value of lost load.

Providing a reasonable estimate for $\hat{C}$ could be done either as an (i) exogenous constant, (ii) through a two-pass procedure, or (iii) approximately in the dispatch. For example, a possible procedure would define the approximating cost function as the least unconstrained cost of the responsive generation dispatch to provide $\hat{g}_R$ of reserves:

$$\hat{C}(\hat{g}_R) = \text{Min}\{C(g_R) | \hat{g}_R = i^t g_R\}.$$

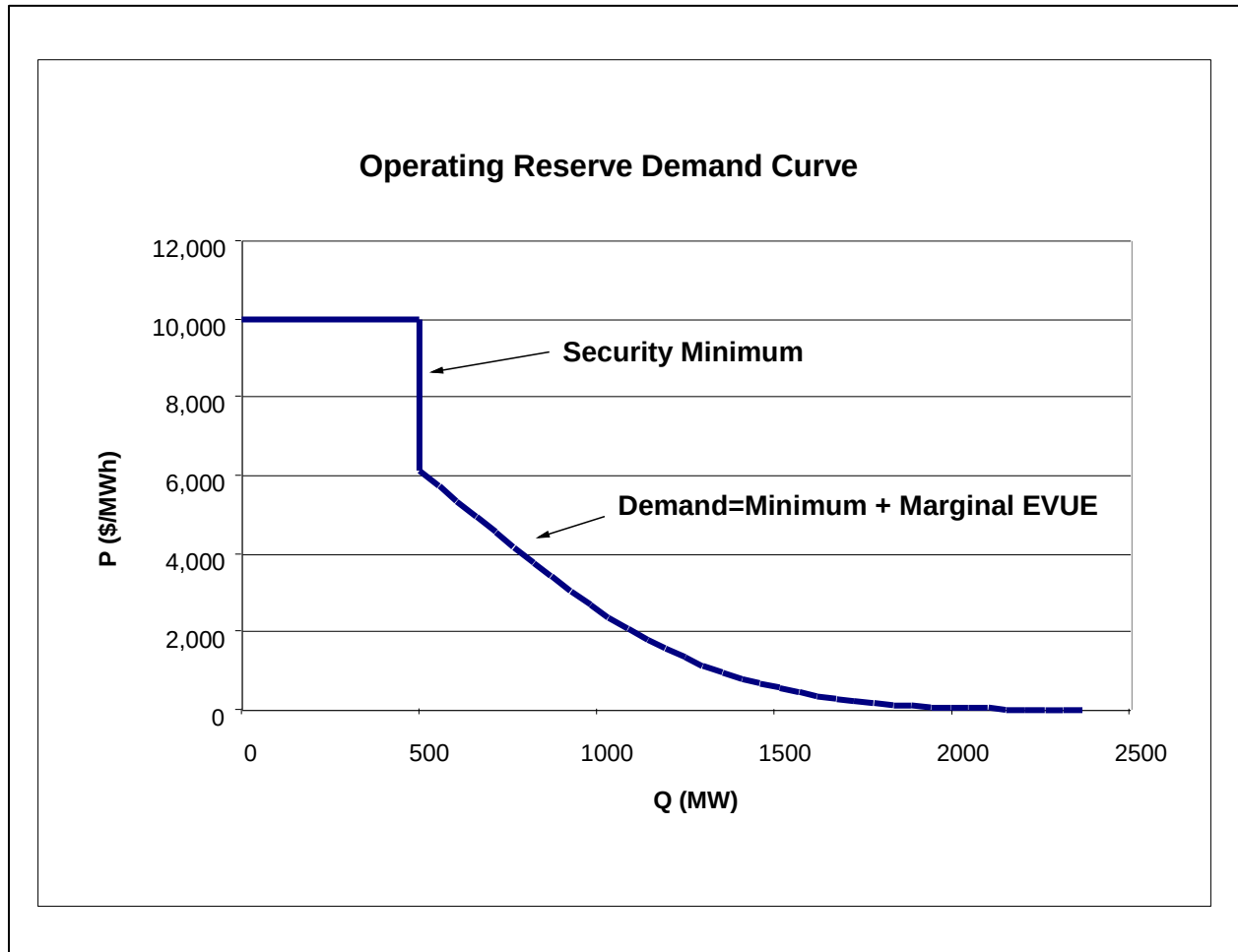
This information would be easy to evaluate before the dispatch.

The loss of load probability calculation could reference zero reserves, or could require a minimum contingency level of reserves that provide the base level for the calculation. To construct the ORDC for responsive reserves that modifies (13) to incorporate the security minimum or last resort reserves X priced at v . Here, $Lolp(r) = \text{Probability}(\text{Net Load Change} \geq r)$. For a candidate value of the aggregate responsive reserves define the corresponding value on the operating reserve demand curve:

$$(14) \quad \pi_R(r_R) = \begin{cases} Lolp(i^t r_R - X), & i^t r_R - X \geq 0 \\ 1, & i^t r_R - X < 0 \end{cases}$$

$$P_R(r_R) = v \pi_R(r_R).$$

This defines the ORDC for responsive reserves with contingency minimum X , as illustrated in Figure 5. The corresponding reserve value is the area under the ORDC defined by the minimum level and the marginal expected value of unserved energy (EVUE).

Figure 5

With this definition, the price of energy is the marginal cost of energy plus the scarcity value, and is bounded by *VOLL*.

Multiple Emergency Actions

The basic logic extends to the case where there are multiple stages of emergency actions triggered by a low level of responsive reserves. The price of reserves is defined by the willingness to pay at the margin to obtain an additional unit of reserves. If emergency actions need be taken ex-ante, then the willingness to pay will be at least the cost of the emergency action. In addition, the value of reserves would be at least the ex-post value of an increment of reserves given the probability distribution of the net load change relative to the anticipated dispatch of the net load.

For example, suppose that we have three emergency actions, with limited capacity, where only the last requires involuntary curtailment of load at the full *VOLL*. Let the first two actions have values of emergency action $VEA_1 < VEA_2 < VOLL$, and available capacities KEA_1, KEA_2 . Define the contingency minimum for reserves at X_3 where the *VOLL* applies. Let the other breakpoints be:

$$\begin{aligned} X_2 &= X_3 + KEA_2 \\ X_1 &= X_2 + KEA_1 \end{aligned}$$

Then define $\nu(s)$, including the minimum contingency levels and emergency actions, as the greater of the ex-ante cost and the expected cost of using the emergency action given the level of reserves in the event that there is a deviation for the forecast net load. Here $VOLL$ and values of various emergency actions are set net of the marginal cost of energy dispatch $\bar{c}$.

$$(15) \quad \nu(s) = \begin{cases} VOLL, & s \leq X_3 \\ \text{Max}(VOLL * Lolp(s - X_3), VEA_2), & X_3 \leq s \leq X_2 \\ \text{Max}\left(VOLL * Lolp(s - X_3) + \right. \\ \quad \left. VEA_2 * (Lolp(s - X_2) - Lolp(s - X_3)), VEA_1\right), & X_2 \leq s \leq X_1 \\ VOLL * Lolp(s - X_3) + VEA_2 * (Lolp(s - X_2) - Lolp(s - X_3)) \\ \quad + VEA_1 * (Lolp(s - X_1) - Lolp(s - X_2)), & X_1 \leq s \end{cases}$$

Hence, the ex-ante scarcity value for reserves is $P_R(r_R) = \nu(r_R)$.

If the two emergency values are high enough, then given an operating reserve level r above the total $X + KEA_1 + KEA_2$, the marginal value of an increment of responsive operating reserves would be:

$$\begin{aligned} P_R(r) &= VEA_1 [Lolp(r) - Lolp(r + KEA_1)] + VEA_2 [Lolp(r + KEA_1) - Lolp(r + KEA_1 + KEA_2)] \\ &\quad + VOLL [Lolp(r + KEA_1 + KEA_2)]. \end{aligned}$$

This is the expected value component of the ORDC. The full ORDC in the dispatch would include the steps in the emergency response, and the probabilistic value of additional reserves, as in (15).

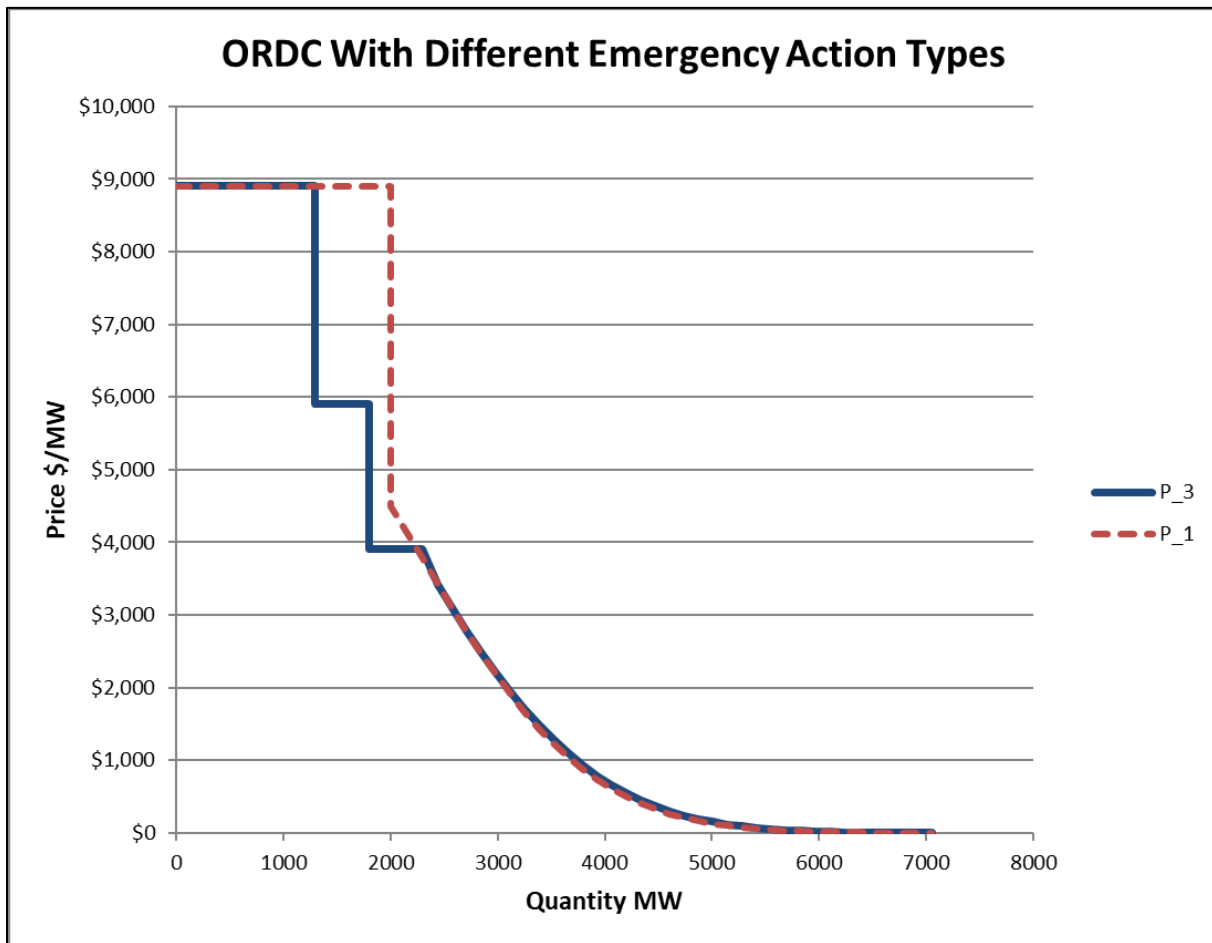
Figure 6

Figure 6 shows an illustrative case, P_3, with the first emergency action at \$4000/MW for 500MW, the second at \$6000 for 500MW, and the final X value of minimum contingency reserves at 1300MW with a $VOLL = \$9000/\text{MW}$. The corresponding emergency action “ X_1 ” value is then at 2300MW. The comparison is with the ORDC P_1 with only one emergency action implemented with $X = 2000\text{MW}$ and $VOLL = \$9000$.³

³ The basic assumptions for the illustrative normal distribution of changes in net load are

Expected Total (MW)	16
Std Dev (MW)	1357.00
$VOLL$ (\$/MWh)	9000
Marginal Dispatch (\$/MWh)	100

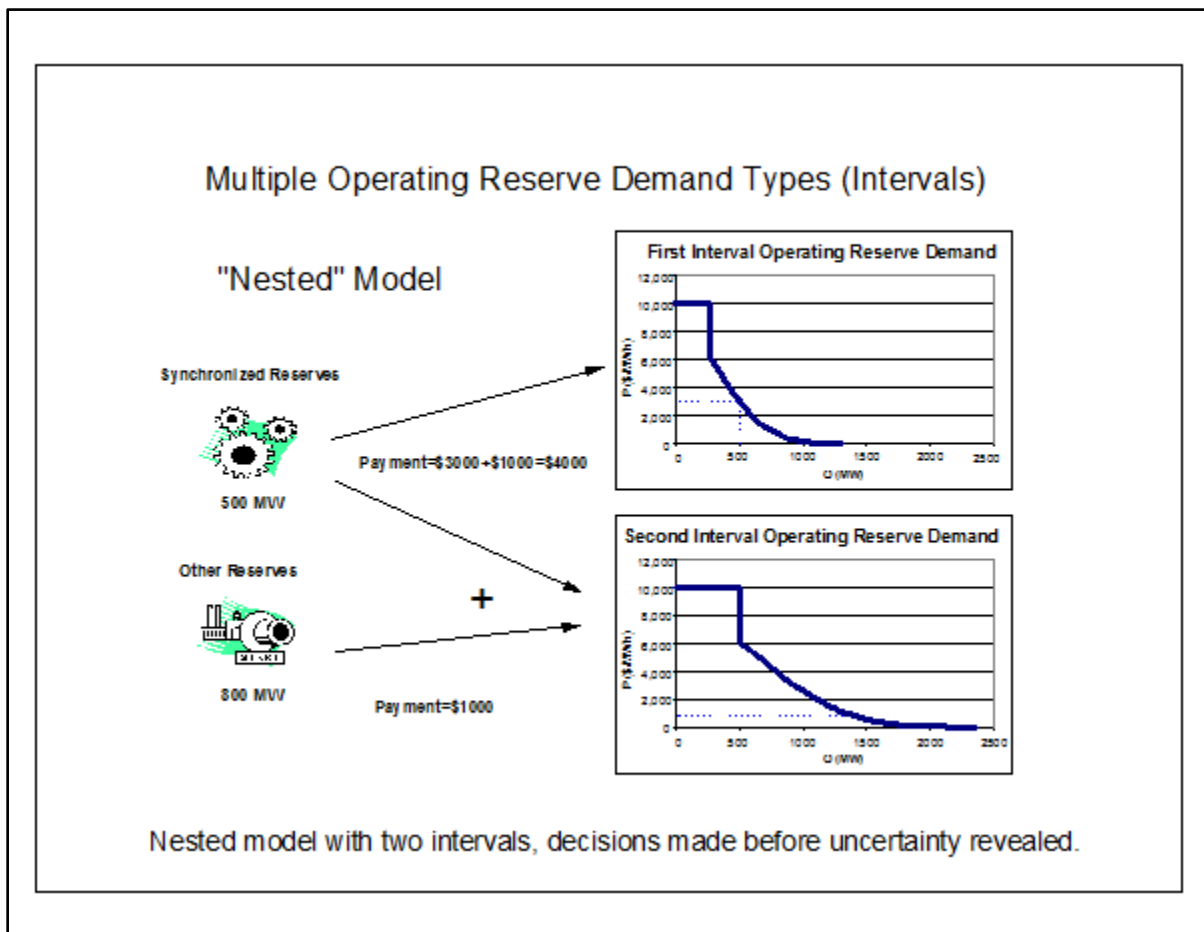
Multiple Reserve Types

The organized market in practice distinguishes several types of reserves. An approximation of the impacts of the different reserve types allows for a cascade model, reflecting different qualities of reserves, and ensure consistent prices that recognize these interactions among reserve types. A generic example with two types of reserves provides the general analysis. This serves as background for a comparison with different implementations.

Two Reserve Types

Setting aside regulation, the principal distinction is between “responsive” reserves (R) and “non-spin” reserves (NS). The ORDC framework can be adapted to include multiple reserves. This section summarizes one such modeling approach with two types of reserves and relates it to the co-optimization examples above. The main distinction is that “responsive” reserves are spinning and have a quick reaction time. These reserves would be available almost immediately and could provide energy to meet increases in net load over the whole of the operating reserve period. By comparison, non-spinning reserves are slower to respond and would not be available for the entire period.

Figure 7

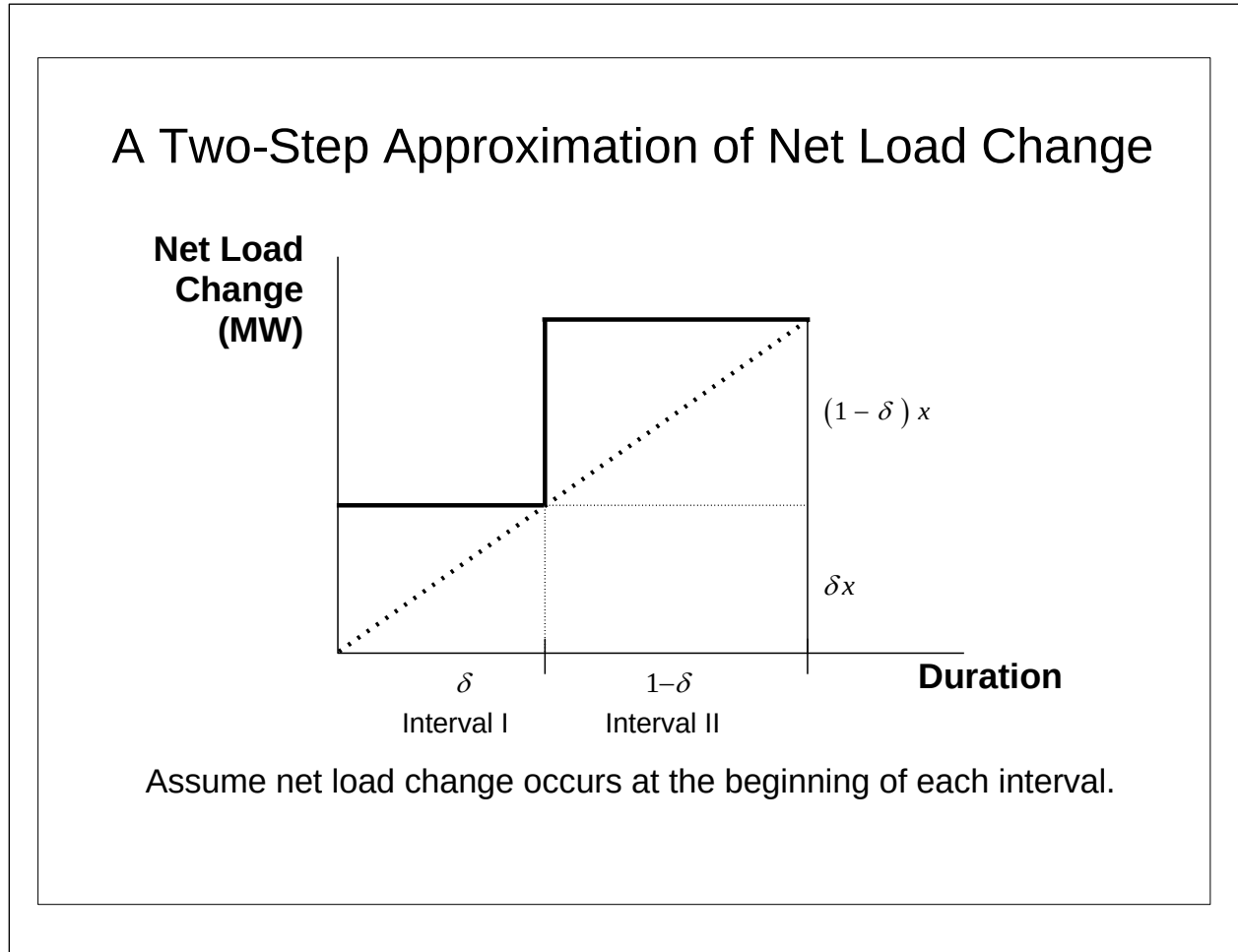


This formulation lends itself to the interpretation of Figure 2 where there are two periods with different demand curves and the models are nested. In other words, responsive reserves r_R can meet the needs in both intervals and the non-spinning reserves r_{NS} can only meet the needs for the second interval.

The proposed model of operating reserves approximates the complex dynamics by assuming that the uncertainty about the unpredicted change in net load is revealed after the basic dispatch is determined. The probability distribution of change in net load is interpreted as applying the change over the uncertain reserve period, say the next hour, divided into two intervals. Over the first interval, of duration (δ), only the responsive reserves can avoid curtailments. Over the second interval of duration ($1-\delta$), both the responsive and non-spin reserves can avoid involuntary load shedding.

In order to keep the analysis of the marginal benefits of more reserves simple, there is an advantage of utilizing a step function approximation for the net load change. (This keeps the marginal value in an interval constant, and we don't have to compute expectations over the varying net load change possible in each period. We only need the total *Lolp* over that interval.)

The standard deviation of the change in net load is for the total over the period. If the change were spread out over the period, then on average it would be more like the diagonal dashed line in Figure 8. An alternative two-step approximation in Figure 8 is that the net load change in the first interval, when only responsive reserves can respond, is proportional to the total load change over the period relative to the length of the first interval, and the second step captures the total change at the beginning of the second interval.

Figure 8

During the first interval, only the responsive reserves apply. In the second interval, both responsive and non-spin reserves have been made available to help meet the net change in load. Suppose that there are two variables y_I, y_{II} representing the incremental net load change in each of the two intervals. Further assume that the two variables have a common underlying distribution for a variable z for total net load change but are proportional to the size of the interval. Then, assuming independence and with x the net load change over the full two intervals, we have:

$$E(y_I) = E(\delta z) = \delta E(z),$$

$$E(y_{II}) = E((1-\delta)z) = (1-\delta)E(z).$$

$$\text{Var}(y_I) = \text{Var}(\delta z) = \delta^2 \text{Var}(z),$$

$$\text{Var}(y_{II}) = \text{Var}((1-\delta)z) = (1-\delta)^2 \text{Var}(z).$$

$$E(z) = E(y_I + y_{II}) = E(x) = \mu.$$

Imposing the independence assumptions, with the hour ahead standard deviation estimated as (σ) , we have:

$$\begin{aligned} \text{Var}(x) &= \text{Var}(y_I + y_{II}) = \text{Var}(y_I) + \text{Var}(y_{II}) = (\delta^2 + (1-\delta)^2) \text{Var}(z). \\ \text{Var}(z) &= \frac{\text{Var}(x)}{\delta^2 + (1-\delta)^2} = \frac{\sigma^2}{\delta^2 + (1-\delta)^2}. \end{aligned}$$

The distinction here is that the implied variance of the individual intervals is greater compared to the one-draw assumption, even though the total variance of the sum over the two intervals is the same as the one draw. This is simply an impact of the square root law for the standard deviation of the sums of independent random variables.

Hence, for the first interval, the standard deviation is $\frac{\delta\sigma}{\sqrt{\delta^2 + (1-\delta)^2}}$, where σ is the standard deviation of the net change in load over both intervals.

Here the different distributions refer to the net change in load over the first interval, and over the sum of the two intervals. The distribution over the sum is just the same distribution for the whole period that was used above. Then $y_I \sim \text{Lolp}_I$, $y_I + y_{II} \sim \text{Lolp}_{I+II}$. A workable approximation would be to utilize the normal distribution for the net load change.

As before, there would be an adjustment to deal with the minimum reserve to meet the max contingency. The revised formulation would include:

$$\begin{aligned} \pi_R(r_R) &= \begin{cases} \text{Lolp}_I(i^t r_R - X), & i^t r_R - X \geq 0 \\ 1, & i^t r_R - X < 0 \end{cases} \\ (16) \quad \pi_{NS}(r_R, r_{NS}) &= \begin{cases} \text{Lolp}_{I+II}(i^t r_R + i^t r_{NS} - X), & i^t r_R + i^t r_{NS} - X \geq 0 \\ 1, & i^t r_R + i^t r_{NS} - X < 0 \end{cases} \\ P_R(r_R, r_{NS}) &= v * (\delta * \pi_R(r_R) + (1-\delta) * \pi_{NS}(r_R, r_{NS})), \\ P_{NS}(r_R, r_{NS}) &= v * (1-\delta) * \pi_{NS}(r_R, r_{NS}). \end{aligned}$$

This representation produces different values for the responsive and non-spin reserves. Let v be the net value of load curtailment, defined as the value of lost load less the avoided cost of energy dispatch offer for the marginal reserve. The interpretation of the prices of reserves, P_R and P_{NS} , is the marginal impact on the load curtailment times Lolp , the probability of the net change in load being greater than the level of reserves, r_R and r_{NS} . This marginal value differs for the two intervals, as shown in the following table:

Marginal Reserve Values		
	Interval I	Interval II
Duration	δ	$1-\delta$
P_R	$vLolp_I(r_R)$	$vLolp_{I+II}(r_R + r_{NS})$
P_{NS}	0	$vLolp_{I+II}(r_R + r_{NS})$

This formulation lends itself to implementation in the co-optimization model. For example, given benchmark estimates for each type of reserves, $(\hat{r}_R, \hat{r}_{NS})$, the problem becomes separable in responsive and non-spin reserves. For example, the benchmark for the current dispatch interval could be set obtained from the co-optimized dispatch solution for the previous dispatch interval. Numerical integration of $P_R(r_R, \hat{r}_{NS})$ and $P_{NS}(\hat{r}_R, r_{NS}) = P_{NS}(0, \hat{r}_R + r_{NS})$ produce separable functions that yield the counterpart benefit functions, $R_I(r_R^0), R_{II}(r_{NS}^0)$. With weak interactions between the types of reserves, the experience with this type of decomposition method suggests that the initial approximation will be good and updating the benchmark estimates in an iterative model could produce rapid convergence to the simultaneous solution (Ahn and Hogan, 1982).

PJM ORDC Proposal

The PJM proposal includes three types of reserve requirements. These are Synchronized (SR), Primary (PR), and 30-Minute (30) reserves. Each requirement has a penalty factor (PF), a minimum reserve requirement (MRR), and an associated probability distribution. For SR and PR, the probability distribution is taken from the empirical 30-minute forecast error look ahead distribution. For the 30-min reserves, the probability distribution is the empirical 1-hour ahead forecast error distribution.

Let the (increasing) MRRs be X_{SR}, X_{PR}, X_{30} . The loss-of-load probability distributions are $Lolp_{30}, Lolp_{60}$. There is a cascade model for the prices and probabilities. The convention here is to distinguish the separate types of reserve products: Synchronized (SR), Non-Synchronized (NSR) and Secondary (SecR) ($r_{SR}, r_{NSR}, r_{SecR}$), recognizing that the SR product contributes to the SR, PR and 30-Minute reserves requirements, the NSR product contributes to the PR and 30-minute reserves requirements and the SecR product contributes to the 30-minute reserves requirement. The relevant probability factors for the three types of reserves become:

$$\begin{aligned}\tilde{\pi}_{SR}(r_{SR}) &= \begin{cases} Lolp_{30}(r_{SR} - X_{SR}), & r_{SR} - X_{SR} \geq 0 \\ 1, & r_{SR} - X_{SR} < 0 \end{cases} \\ \tilde{\pi}_{PR}(r_{SR}, r_{NSR}) &= \begin{cases} Lolp_{30}(r_{SR} + r_{NSR} - X_{PR}), & r_{SR} + r_{NSR} - X_{PR} \geq 0 \\ 1, & r_{SR} + r_{NSR} - X_{PR} < 0 \end{cases} \\ \tilde{\pi}_{30}(r_{SR}, r_{NSR}, r_{SecR}) &= \begin{cases} Lolp_{60}(r_{SR} + r_{NSR} + r_{SecR} - X_{30}), & r_{SR} + r_{NSR} + r_{SecR} - X_{30} \geq 0 \\ 1, & r_{SR} + r_{NSR} + r_{SecR} - X_{30} < 0 \end{cases}.\end{aligned}$$

With these definitions, the single region (RTO-wide) PJM proposed definition of the price approximation is as in:

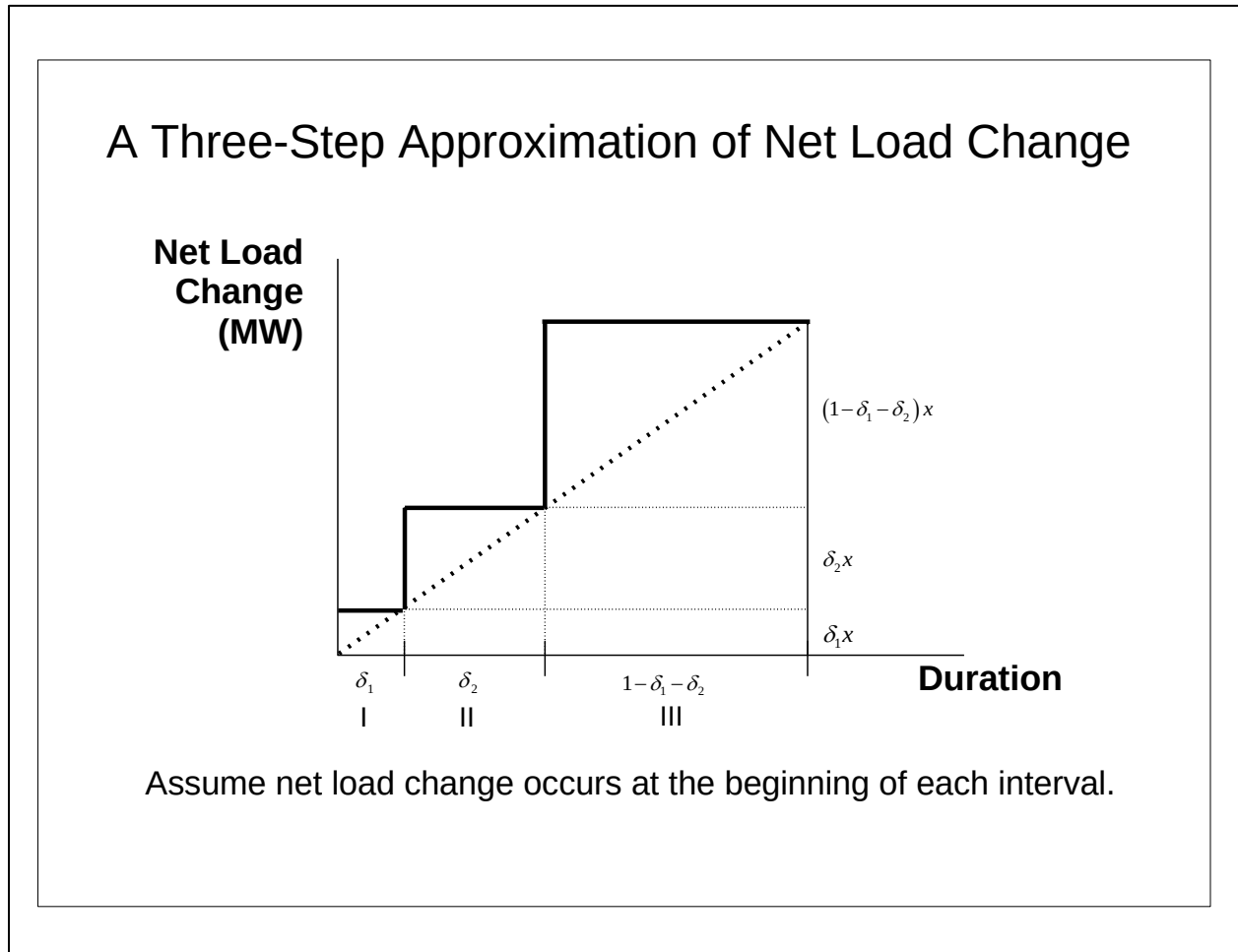
$$\begin{aligned}\tilde{P}_{SR}(r_{SR}, r_{NSR}, r_{SecR}) &= PF_{SR} * \tilde{\pi}_{SR}(r_{SR}) + PF_{PR} * \tilde{\pi}_{PR}(r_{SR}, r_{NSR}) + PF_{30} * \tilde{\pi}_{30}(r_{SR}, r_{NSR}, r_{SecR}) \\ \tilde{P}_{NSR}(r_{SR}, r_{NSR}, r_{SecR}) &= PF_{PR} * \tilde{\pi}_{PR}(r_{SR}, r_{NSR}) + PF_{30} * \tilde{\pi}_{30}(r_{SR}, r_{NSR}, r_{SecR}) \\ \tilde{P}_{SecR}(r_{SR}, r_{NSR}, r_{SecR}) &= PF_{30} * \tilde{\pi}_{30}(r_{SR}, r_{NSR}, r_{SecR}).\end{aligned}$$

Hence, if all reserve levels are below the MRRs, then the SR Market Clearing Price is the sum of the three penalty factors, the NSR Market Clearing Price is the sum the PR and 30-min penalty factors, and the SecR Market Clearing Price is the 30-min penalty factor. Otherwise the prices incorporate the respective *Lolps*.

VOLL Approach with Three Reserve Types

The PJM approach uses three types reserves corresponding to three different response intervals. Comparison with the methodology above for the cascaded model, begins with the observation that the price approximation in the *VOLL* approach assumes that the different reserve products apply over different periods. This ties back to a characterization of the timing of and probability distribution for revealed information about the net load change.

The assumption here is that there are three periods defined as: I, 0-10 minutes; II, 10-30 minutes; and III, 30-60 minutes. The net load change approximation follows a step function as shown in the figure. The increment in reserve requirements occurs at the beginning of each interval, and that change persists over the rest of the one-hour period.

Figure 9

The first step SR reserves can meet the requirement for all three periods, but the marginal value of the reserves is different for each of the three periods. Similarly, for the other reserve types.

The *Lolp* approximation for each period starts with the hourly distribution of forecast errors. In order to treat the three periods as independent in adding up the prices, the estimated mean and variance for each period is scaled to be consistent with the variance for the full look ahead period. Suppose that there are three underlying variables y_I, y_{II}, y_{III} representing the incremental net load change in the three intervals. Further assume that the three variables have a common underlying distribution for a variable z but are proportional to the size of the interval. Then, assuming independence and with x the net load change over the full three intervals, we have:

$$\begin{aligned}
E(y_I) &= E(\delta_1 z) = \delta_1 E(z), \\
E(y_{II}) &= E(\delta_2 z) = \delta_2 E(z), \\
E(y_{III}) &= E(\delta_3 z) = \delta_3 E(z). \\
Var(y_I) &= Var(\delta_1 z) = \delta_1^2 Var(z), \\
Var(y_{II}) &= Var(\delta_2 z) = \delta_2^2 Var(z), \\
Var(y_{III}) &= Var(\delta_3 z) = \delta_3^2 Var(z), \\
E(z) &= E(y_I + y_{II} + y_{III}) = E(x) = \mu.
\end{aligned}$$

Imposing the independence assumptions, with the hour ahead standard deviation estimated as (σ) , we have:

$$\begin{aligned}
Var(x) &= Var(y_I + y_{II} + y_{III}) = Var(y_I) + Var(y_{II}) + Var(y_{III}) = (\delta_1^2 + \delta_2^2 + \delta_3^2) Var(z). \\
Var(z) &= \frac{Var(x)}{\sum \delta_i^2} = \frac{\sigma^2}{\sum \delta_i^2}.
\end{aligned}$$

The distinction here is that the implied variance of the individual intervals is greater compared to the one-draw assumption, even though the total variance of the sum over the two intervals is the same. This is simply an impact of the square root law for the standard deviation of the sums of independent random variables.

Here the different distributions refer to the net change in load over the first interval, and over the sum of the relevant intervals. The distribution over the final sum is just the same distribution for the whole period that was used above. Then:

$$y_I \sim Lolp_I, \quad y_I + y_{II} \sim Lolp_{I+II}, \quad y_I + y_{II} + y_{III} \sim Lolp_{I+II+III}.$$

A workable approximation would be to utilize the normal distribution for the net load change.

As before, there would be an adjustment to deal with the minimum reserve to meet the max contingency. The revised formulation would include:

$$\begin{aligned}
\pi_{SR}(r_{SR}) &= \begin{cases} Lolp_I(r_{SR} - X_{SR}), & r_{SR} - X_{SR} \geq 0 \\ 1, & r_{SR} - X_{SR} < 0 \end{cases} \\
\pi_{PR}(r_{SR}, r_{PR}) &= \begin{cases} Lolp_{I+II}(r_{SR} + r_{PR} - X_{PR}), & r_{SR} + r_{PR} - X_{PR} \geq 0 \\ 1, & r_{SR} + r_{PR} - X_{PR} < 0 \end{cases} \\
\pi_{30}(r_{SR}, r_{PR}, r_{30}) &= \begin{cases} Lolp_{I+II+III}(r_{SR} + r_{PR} + r_{30} - X_{30}), & r_{SR} + r_{PR} + r_{30} - X_{30} \geq 0 \\ 1, & r_{SR} + r_{PR} + r_{30} - X_{30} < 0 \end{cases}.
\end{aligned}$$

With the *VOLL* (adjusted for marginal generation cost) of v , the corresponding prices would be:

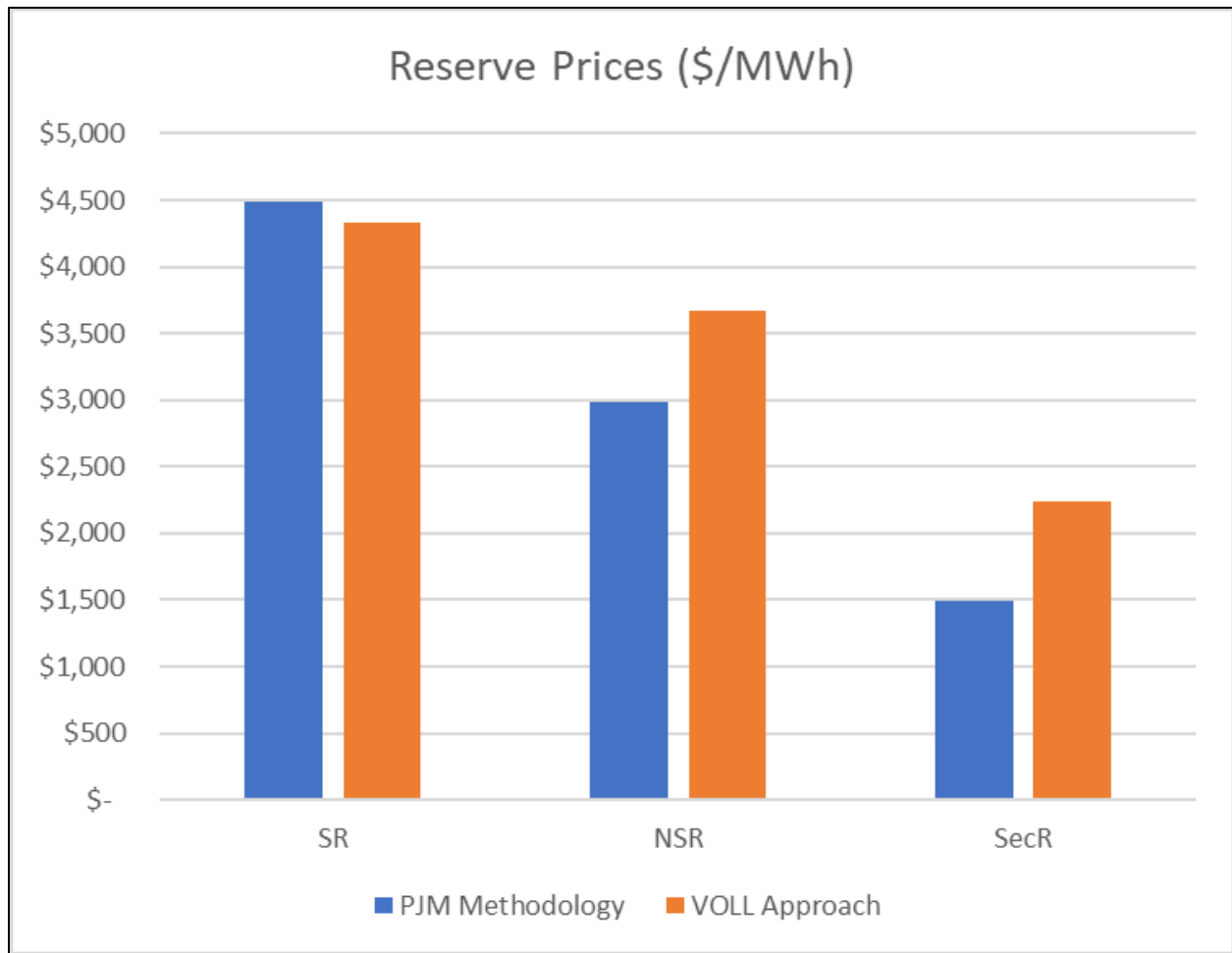
$$\begin{aligned}
P_{SR}(r_{SR}, r_{PR}, r_{30}) &= v * (\delta_1 * \pi_{SR}(r_{SR}) + \delta_2 * \pi_{PR}(r_{SR}, r_{PR}) + \delta_3 * \pi_{30}(r_{SR}, r_{PR}, r_{30})) \\
P_{PR}(r_{SR}, r_{PR}, r_{30}) &= v * (\delta_2 * \pi_{PR}(r_{SR}, r_{PR}) + \delta_3 * \pi_{30}(r_{SR}, r_{PR}, r_{30})) \\
P_{30}(r_{SR}, r_{PR}, r_{30}) &= v * \delta_3 * \pi_{30}(r_{SR}, r_{PR}, r_{30}).
\end{aligned}$$

Here $v * \delta_i$ looks similar to the PF_i in the PJM proposal; however, there is also a difference in the approximation of the probabilities and the duration of the period for avoided emergency action.

Illustrative Comparison

For purposes of an illustrative calculation, consider an empirical distribution for actual reserves, viewed from the standpoint of a 30-minute look-ahead, as having approximately a mean of 400 MW and a standard deviation of 600 MW. For the illustration here, double these values and assume this defines the actual reserve distribution with a 60-minute look-ahead forecast, using the Normal Distribution approximation to simplify the calculation. Assume the three MRR values are given, one for each type of reserves. The price for anchoring the demand curve for each of the three individual reserve products at the level equal to the corresponding MRR, would be the price corresponding to the highest probability of this type of reserves falling below its MRR. Therefore, these would be the highest reserve prices for reserves at or above the MRR levels. The corresponding *VOLL* is \$6000, equal to the sum of the three assumed penalty factors of \$2000.

With these assumptions, Figure 10 summarizes the three reserve prices compared between the two approximation methods. The prices are different principally due to differences in the scaling assumptions for the three different periods. Both approximations are consistent with a significant estimate of the *VOLL*, compared to the existing PJM \$850/MWh maximum penalty factor.

Figure 10

These are the unconstrained prices for the RTO region. If there is a constrained region, the PJM increment in prices follows the same methodology. Hence, if the regional parameters for load, probability distributions, and MRR scale proportionally, then for the same level of product reserves at the MRR in the constrained zone, the resulting product reserves prices would double the levels shown in Figure 10, consistent with a *VOLL* in the constrained zone of \$12,000/MWh.

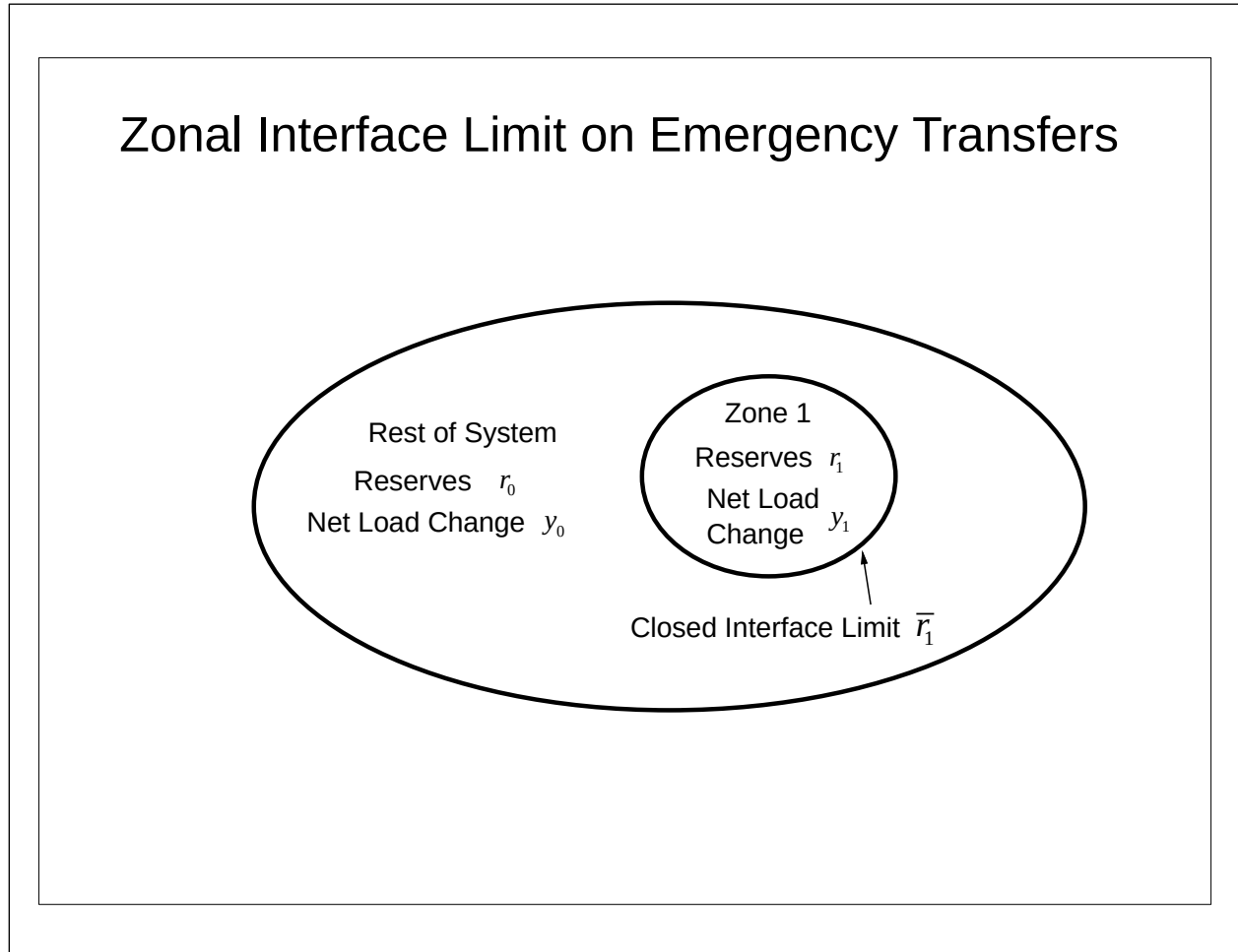
Multiple Zones and Locational Operating Reserves

The assumption that there is a single system-wide operating reserve benefit may need to be modified. The steady-state constraints of transmission limits and loop flows apply to the base dispatch. These constraints need not apply necessarily to the short-term use of operating reserves in a stressed situation. However, it is possible a set of transmission limits includes locational constraints on operating reserves. An approach for modeling locational operating reserves is to define a nested zone and the associated interface constraint that limits the emergency movement of power. This constraint then separates the reserves inside and outside the constrained region and defines their interaction.

The task is to define a locational operating reserve model that approximates and prices the dispatch decisions made by operators. To illustrate, consider the simplest case with one constrained zone and the rest of the system. The reserves are defined separately and there is a known transfer limit for the closed interface between the constrained zone and the rest of the system. This zonal interface constraint would be analogous to the Capacity Emergency Transfer Limit in PJM planning models (PJM, 2016). The probability distribution for net load changes would be estimated separately for locations inside and outside the zone. The zonal requirements for operating reserves interact with energy and economic dispatch, incorporate local interface constraints, and provide compatible short-term prices for operating reserves and interface capacity. This basic argument leads to a simple numerical model that can incorporate multiple embedded zones and interface constraints and be implemented with the co-optimization framework for energy and reserves.

An outline of the basic framework illustrates the representation of locational operating reserve demand curves. Adaptation of a single system ORDC to address locational reserve requirements raises additional issues.

To illustrate, consider the simplest case with one constrained zone and the rest of the system, as in Figure 11. The regions are nested, meaning that the locational requirement is a subset of the system requirement. The reserves are defined separately for the system and within the local region, but they interact and there is a known transfer limit for the closed interface between the constrained zone and the rest of the system.

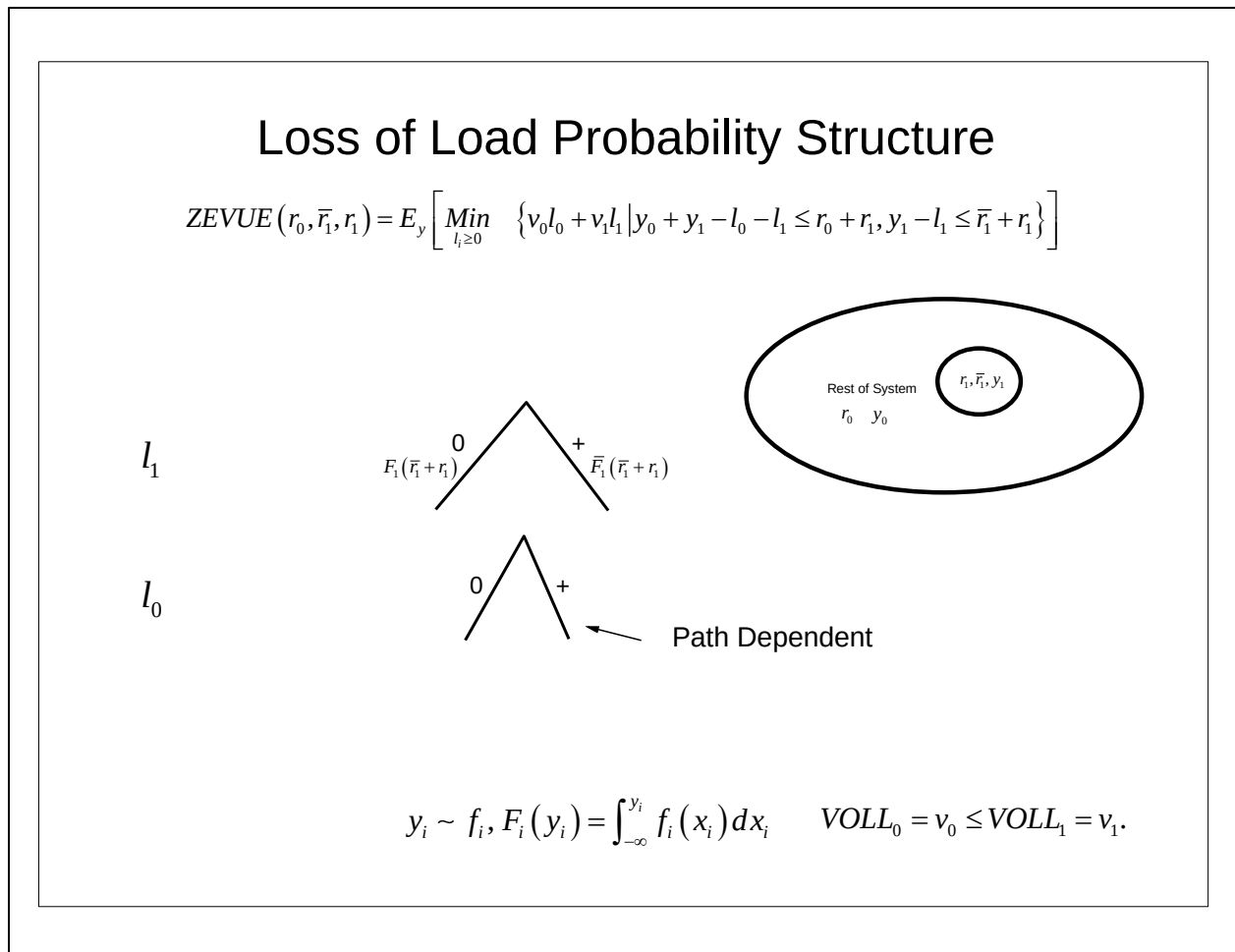
Figure 11

The interior Zone 1 has a known level of reserves r_1 . The distribution of net load changes within the zone is $y_1 \sim f_1$. The closed interface defines the interior zone by a limit $\bar{r}_1$ on the aggregate power flow from the rest of the system into the local zone. This limit will interact with the dispatch power flow. The rest of system has a known level of reserves r_0 and a distribution of net load changes outside of the interior zone, $y_0 \sim f_0$. These are treated as independent distributions. Independence is not a strong assumption. The dispatch load forecast might be strongly interacting across the zones, but the unanticipated deviations from the forecast can be viewed as approximately independent across the zones.

The distributions for each net load change have corresponding cumulative distributions.

$$y_0 \sim f_0, y_1 \sim f_1, \quad F_0(y_0) = \int_{-\infty}^{y_0} f_0(x_0) dx_0, \quad F_1(y_1) = \int_{-\infty}^{y_1} f_1(x_1) dx_1.$$

The zonal expected value of unserved energy (ZEVUE) would be an added component of the objective function in economic dispatch. A simplifying assumption is only one type of emergency action in each zone. Further, assume that the $v_1 = VOLL_1 - \bar{c}_1$ is at least as great as the corresponding value in the rest of the system, $v_0 = VOLL_0 - \bar{c}_0$. With this assumption, we adopt the protocol that gives priority to meeting load deviations inside the constrained zone relative to the rest of the system, and the ex-post dispatch will have a simple structure. In Figure 12, the first priority is to meet the net change of load within the interior zone. The unserved load l_i will be penalized at the respective value of loss load.

Figure 12

The basic problem determines the configuration of lost load and the ZEVUE.

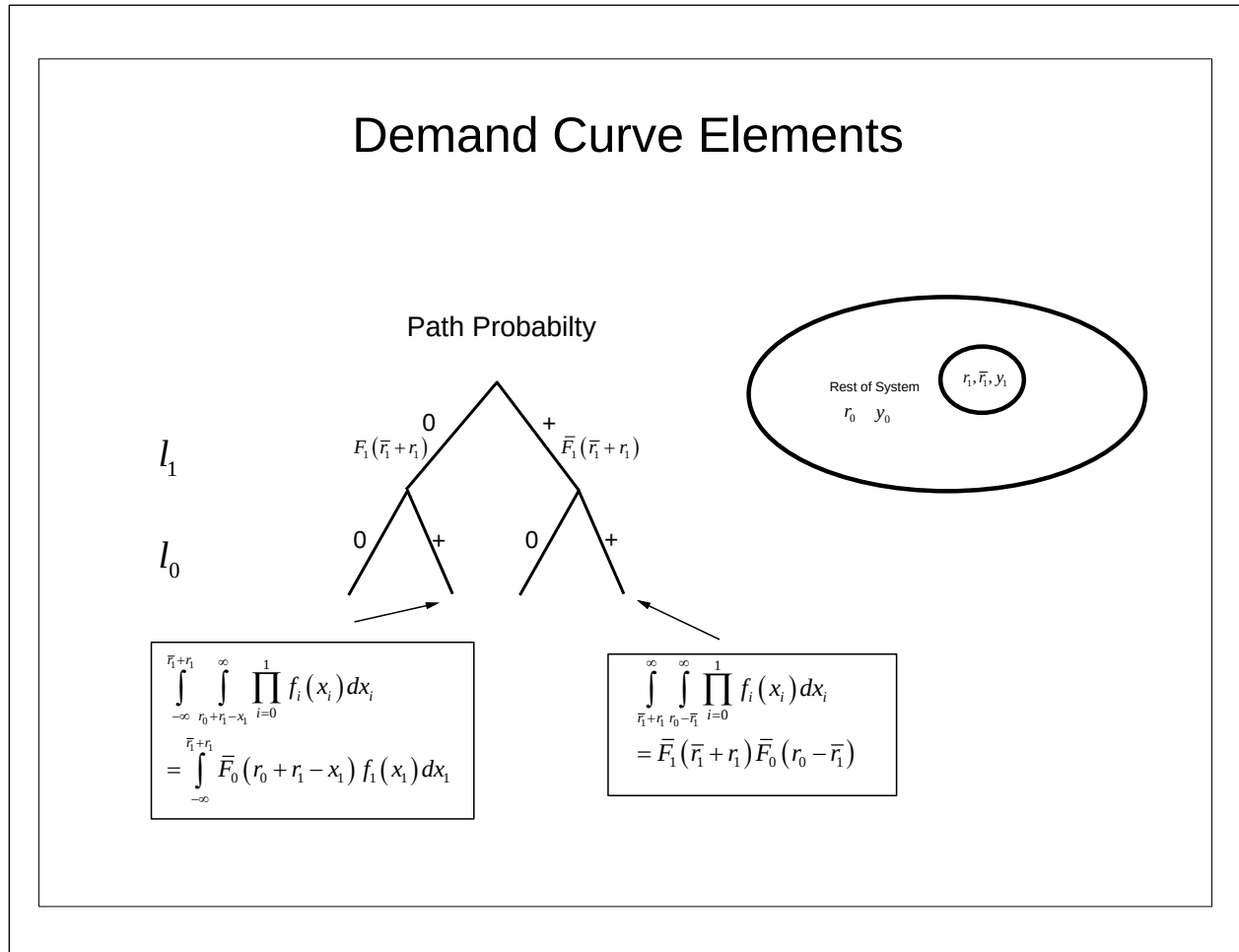
$$ZEVUE(r_0, \bar{r}_1, r_1) = E_y \left[\text{Min}_{l_i \geq 0} \left\{ v_0 l_0 + v_1 l_1 \mid y_0 + y_1 - l_0 - l_1 \leq r_0 + r_1, y_1 - l_1 \leq \bar{r}_1 + r_1 \right\} \right].$$

The derivatives of ZEVUE define the demand curves for operating reserves. Given the simplifying assumptions, the tree structure in Figure 13 illustrates the steps to construct these prices for

reserves and the interface constraint. At the top of the branching is the amount of lost load in region 1. This is either zero or positive, and the probabilities on the branches apply for these conditions. The key is the limit on internal reserves and the interface limit. If the net change in load inside the zone is greater than $\bar{r}_1 + r_1$ then all the reserves inside the region and all that could move from outside the region would be utilized, and there would be loss of load inside the region. This occurs with probability $\bar{F}_1(\bar{r}_1 + r_1) = 1 - F_1(\bar{r}_1 + r_1)$. Likewise, the left branch with $l_1 = 0$ has probability $F_1(\bar{r}_1 + r_1)$.

The probabilities for the next level down are path dependent, but the calculation is conceptually straightforward.

Figure 13

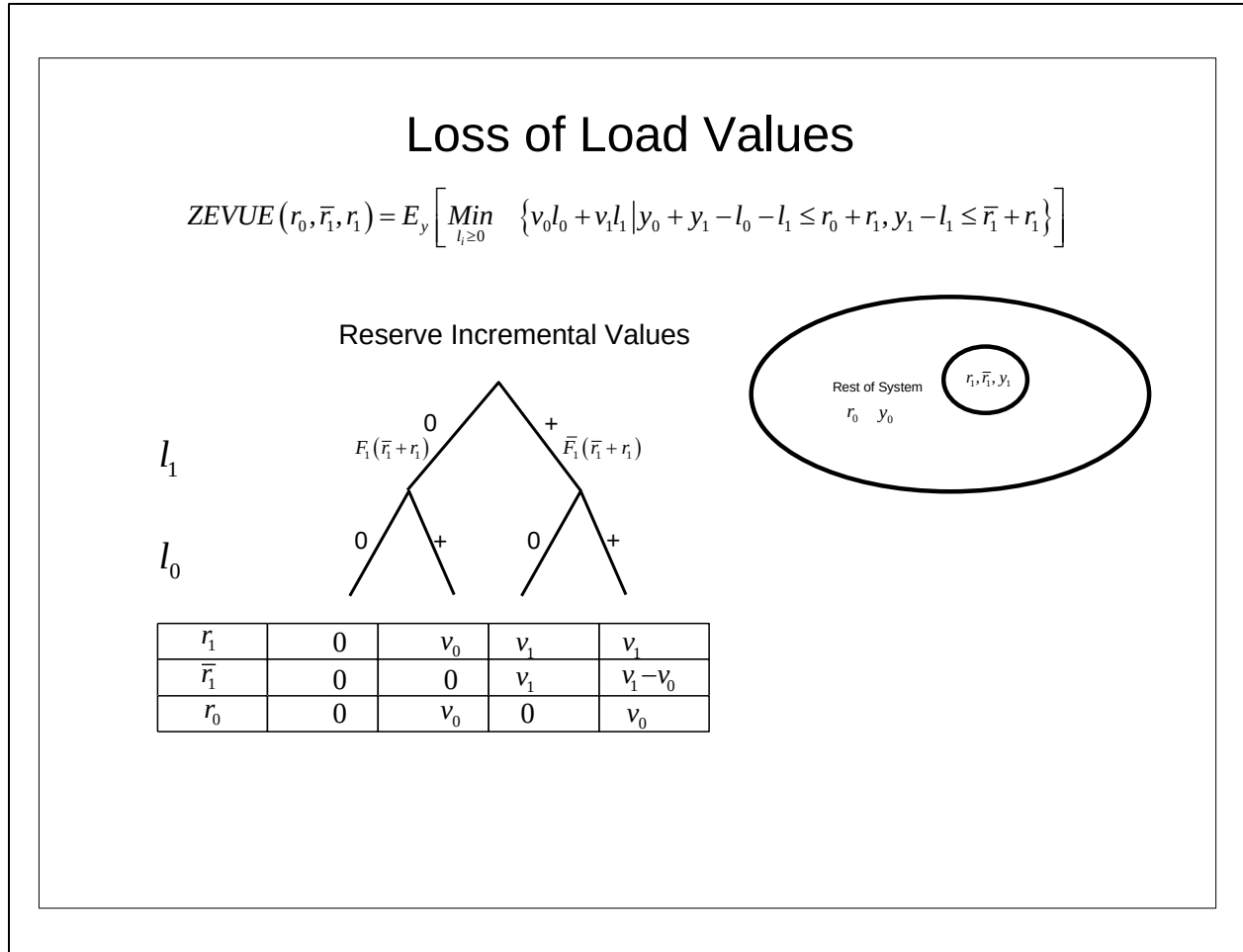


For example, in Figure 13, given that we are on the path with $l_1 \geq 0$, the reserves available for the rest of the region must be the total rest-of-system reserves minus the interface capacity, because the interface capacity is being used to meet requirements in the constrained zone. The conditional

probability of this case is $\bar{F}_0(r_0 - \bar{r}_1)$. Hence, the probability for the full path is $\bar{F}_1(\bar{r}_1 + r_1)\bar{F}_0(r_0 - \bar{r}_1)$, as shown in Figure 13. A similar argument applies to the other paths.

The full ZEVUE is difficult to characterize and calculate. However, inspection of the possible configurations of outages reveals the marginal zonal values of unserved energy, which define the locational demand curves for operating reserves.

Figure 14

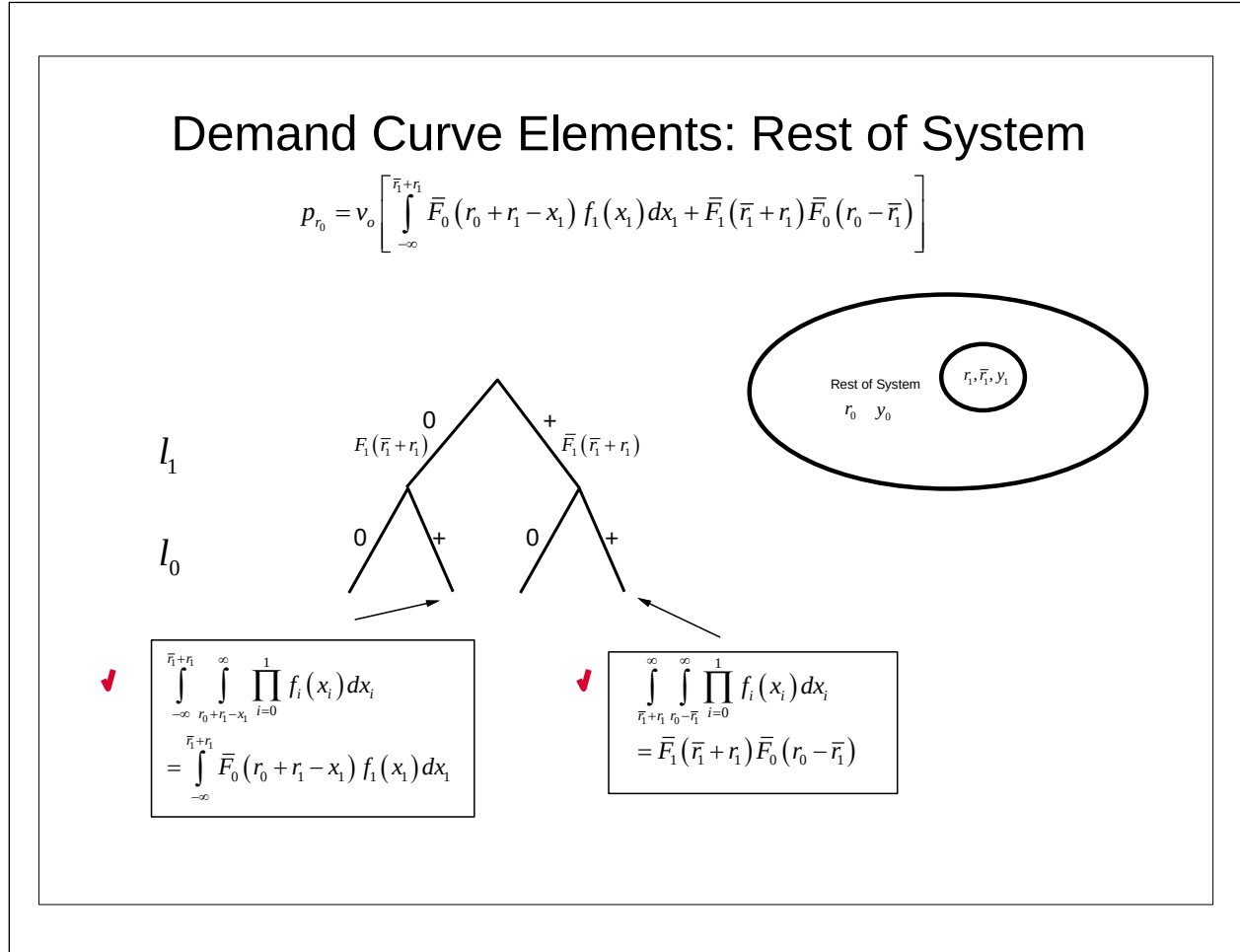


The table in Figure 14 illustrates the reserve incremental values on each of the paths. For example, on the right-most path, the marginal value of reserves inside the region is v_1 and the marginal value in the rest of the region is v_0 , because there are load losses in both regions. On this same path, the marginal value of incremental interface capacity is the increased flow from outside to inside, which would produce net benefit $v_1 - v_0$. Similar arguments apply to the other elements of the table. And with this table we see the paths where values are non-zero and we need the associated path probabilities.

Combining the marginal values and probabilities for each path in the tree yields the corresponding value which defines the expected marginal value of the increment of reserves or interface capacity.

For example, Figure 15 shows the demand curve for the price of reserves in the rest of the system, with the check marks showing the relevant paths.

Figure 15



The demand is a function of all three elements and the associated probability distributions.

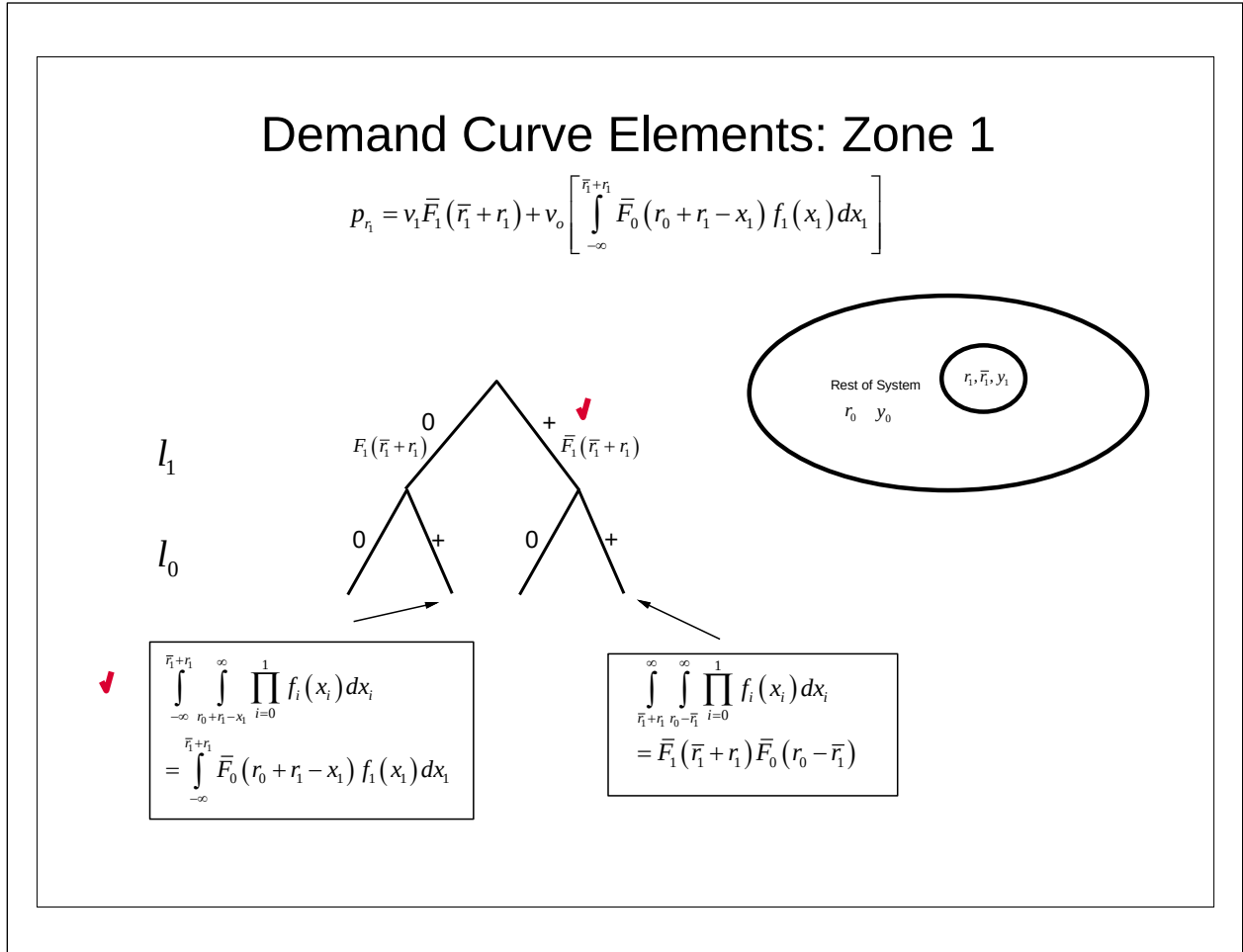
$$(17) \quad p_{r_0} = v_o \left[\int_{-\infty}^{\bar{r}_1 + r_1} \bar{F}_0(r_0 + r_1 - x_1) f_1(x_1) dx_1 + \bar{F}_1(\bar{r}_1 + r_1) \bar{F}_0(r_0 - \bar{r}_1) \right].$$

Since all these elements are known, it is a simple calculation to trace out the elements of the demand curve to include in the dispatch objective function and solve for energy and reserves.

There is a similar story for the price of reserves inside the local zone in Figure 16.

$$(18) \quad p_{r_1} = v_1 \bar{F}_1(\bar{r}_1 + r_1) + v_o \left[\int_{-\infty}^{\bar{r}_1 + r_1} \bar{F}_0(r_0 + r_1 - x_1) f_1(x_1) dx_1 \right].$$

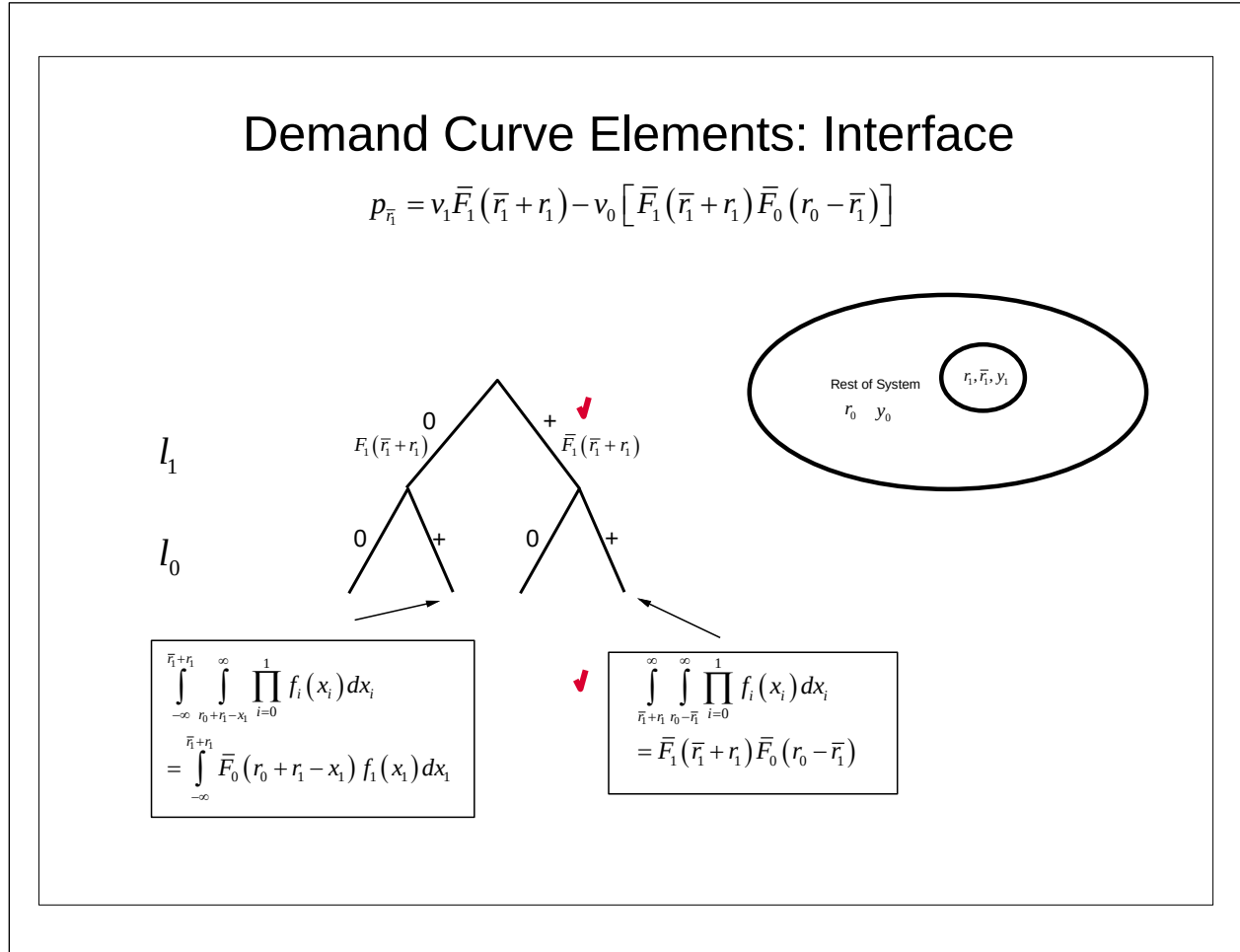
Figure 16



Finally, the analysis extends to the demand curve for interface capacity in Figure 17.

$$p_{\bar{r}_1} = v_1 \bar{F}_1(\bar{r}_1 + r_1) - v_0 [\bar{F}_1(\bar{r}_1 + r_1) \bar{F}_0(r_0 - \bar{r}_1)].$$

Figure 17



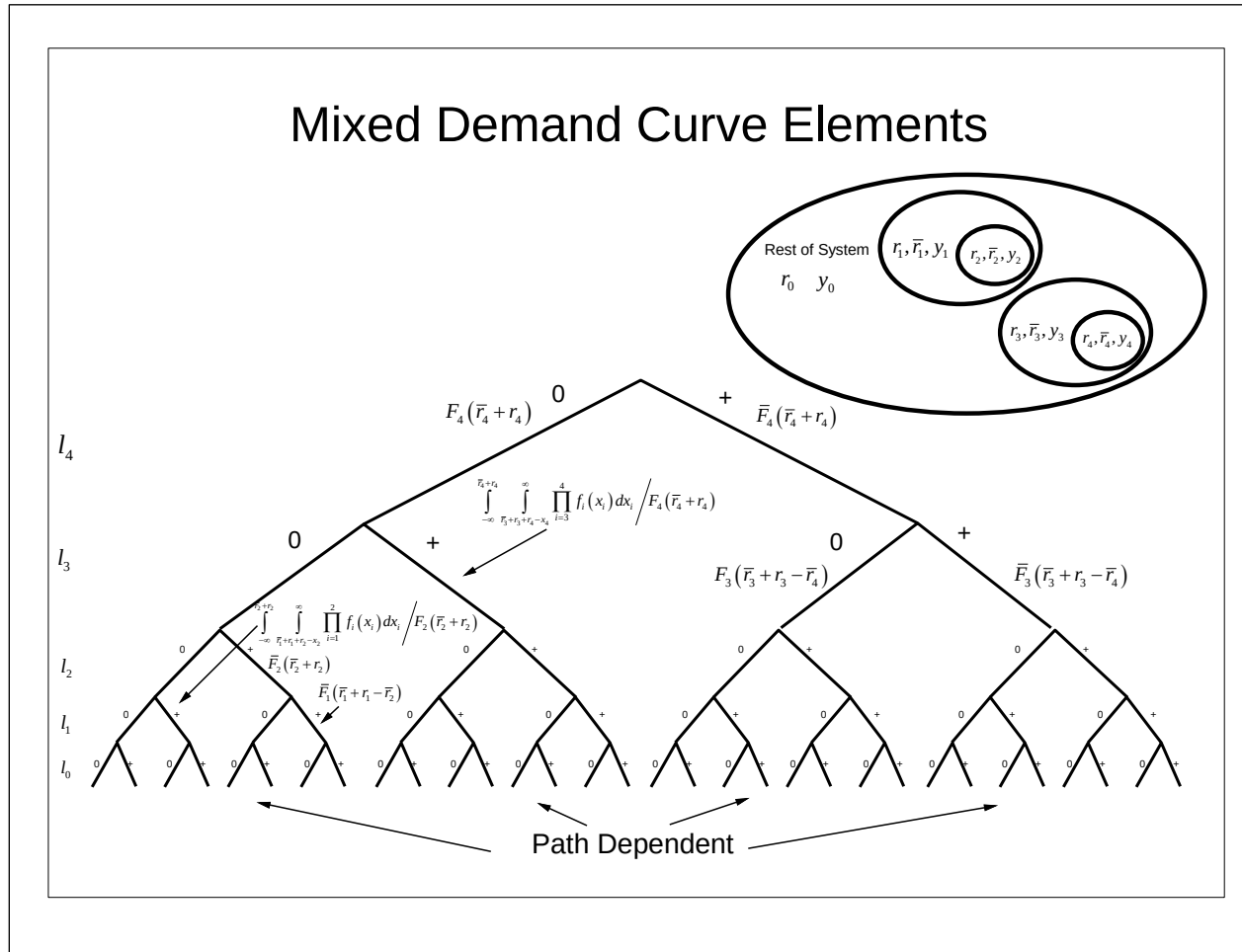
Although the values for each reserve differ in each case on the tree, the expected values defining the reserve prices satisfy $p_{r_i} = p_{r_0} + p_{\bar{r}_1}$.

The extensions to include multiple zones or further nested zones would follow a similar logic. At some stage the “curse of dimensionality” would make the size of the probability tree too large to maintain computational tractability. However, the simple structure could well accommodate a few zones.

The illustration in Figure 18 suggests the basic structure with parallel and nested zones. On each path there would be an algorithm for numerically integrating the probabilities to obtain the path weights. And there would be a corresponding table of marginal values of each zonal reserve and

interface constraint (Hogan, 2010). The resulting demand curves could be included in the dispatch logic.

Figure 18

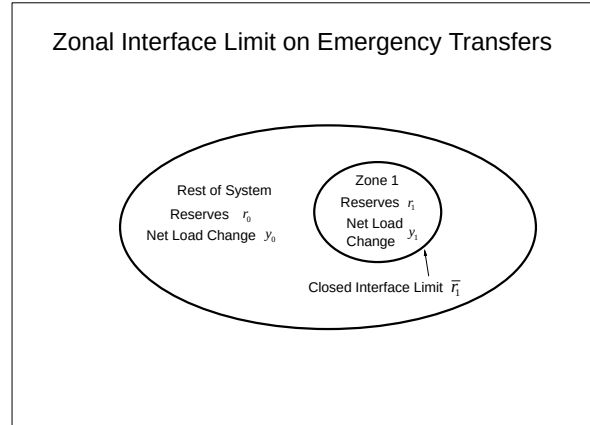


Constrained Zone Example

An example illustrates the separable implementation of three locational reserve-related demand curves. The parameter assumptions and an assumed benchmark provide the components for the approximation.

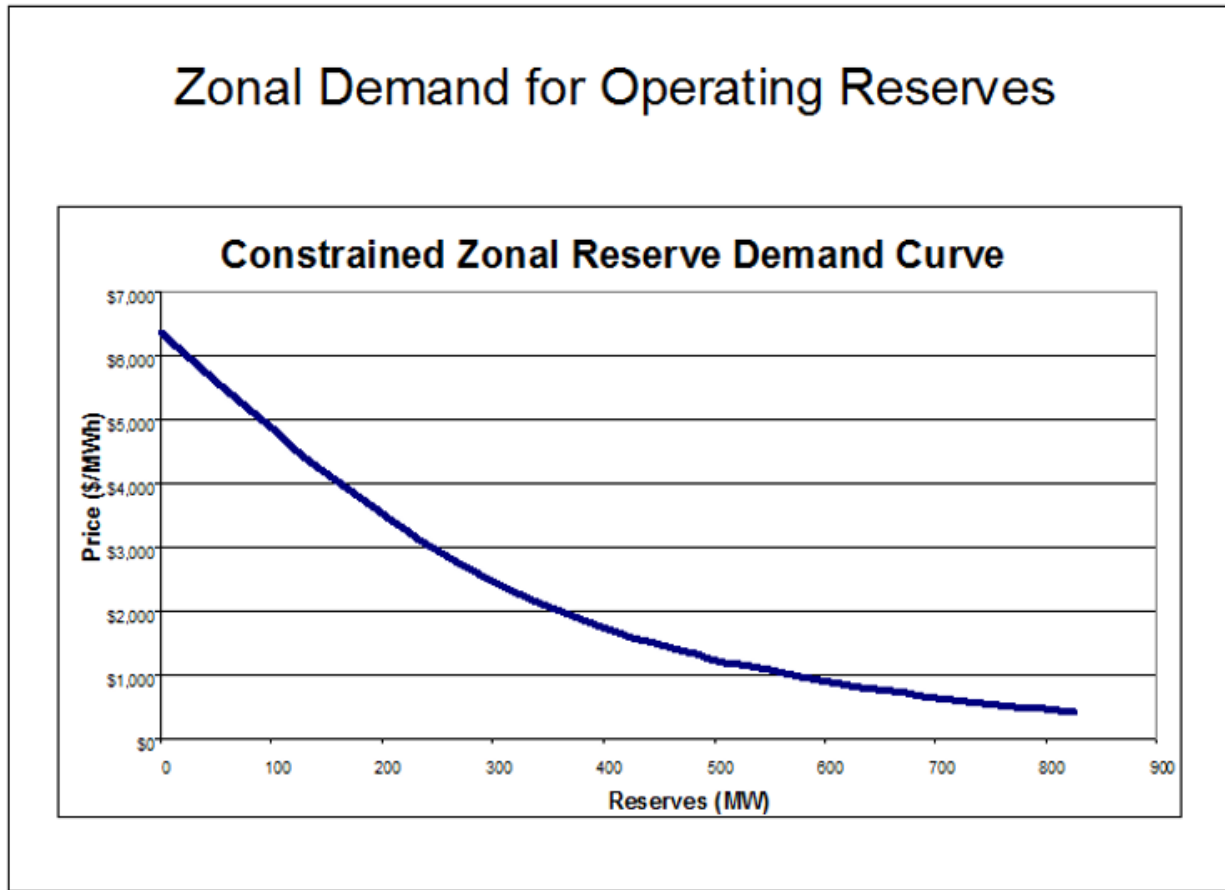
	ROS	Zone
Expected Total (MW)	107.1	45.90
Std. Dev (MW)	488.99	209.57
VOLL (\$/MWh)	7000	10000

	ROS	Zone 1	Interface
Benchmark (MW)	160.65	68.85	45.90



With these assumptions, we can use the normal approximation of the net load changes to calculate the corresponding probabilities on each path and the resulting estimates of the reserve-related prices. For the price in the constrained zone we have:

$$p_{r_1} = v_1 \left(1 - F_1(\bar{r}_1 + r_1) \right) + v_0 \int_{-\infty}^{\bar{r}_1 + r_1} \left[1 - F_0(r_0 + r_1 - x_1) \right] f_1(x_1) dx_1.$$

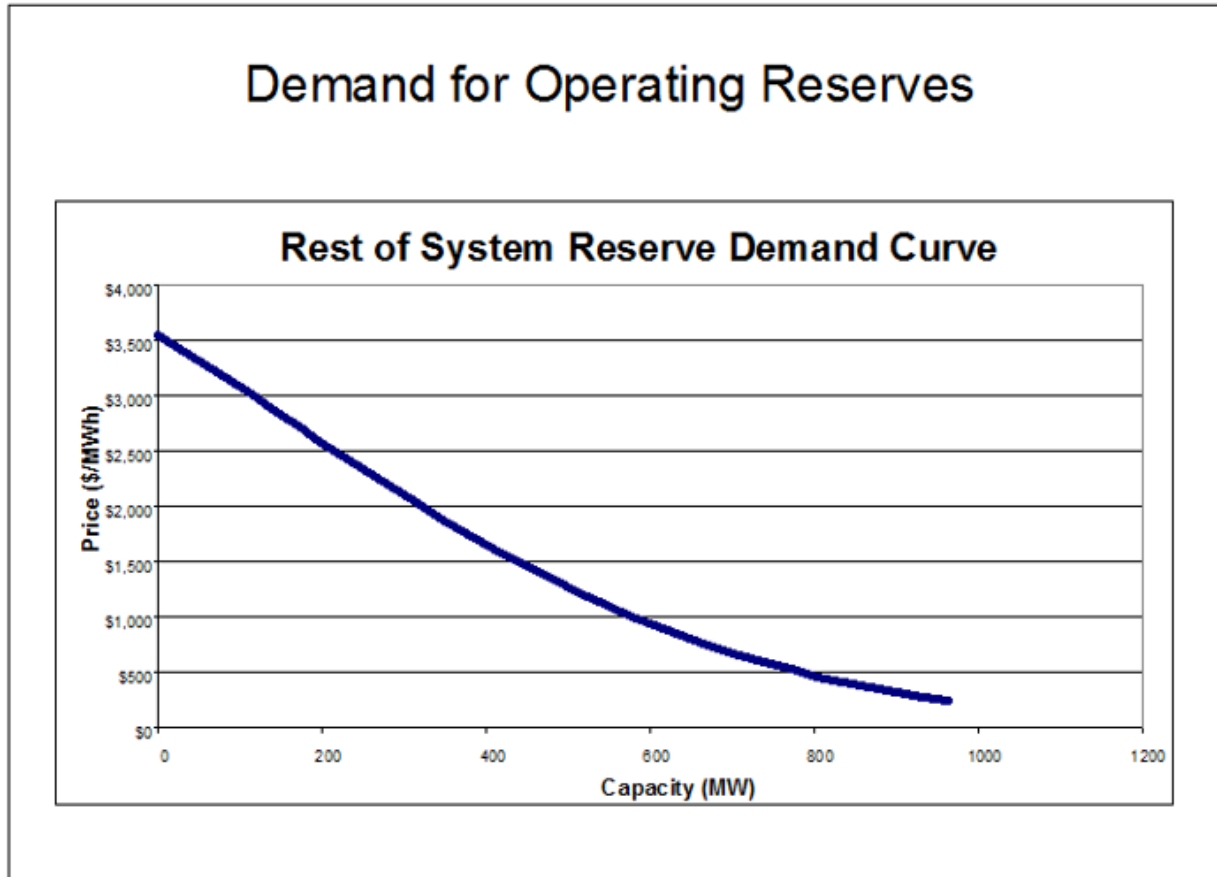
Figure 19

The maximal zonal price in Figure 19 is slightly over \$6,000/MWh, determined by the value of lost load and the loss of load probability.

For the price of reserves on the rest of the system we have:

$$p_{r_0} = v_0 \int_{r_0 - \bar{r}_1}^{\infty} [1 - F_1(r_0 + r_1 - x_0)] f_0(x_0) dx_0.$$

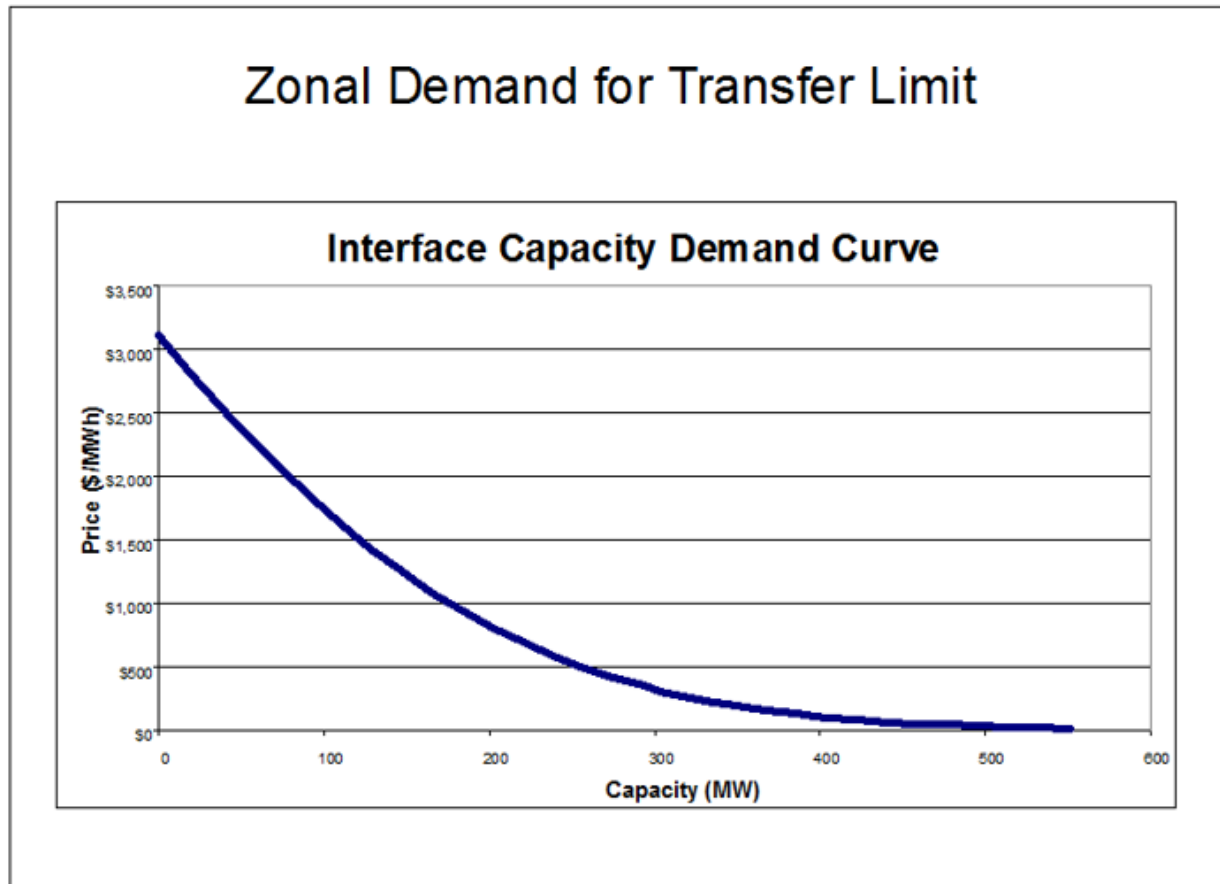
Figure 20



The maximal rest of the system price in Figure 20 is slightly over \$3,500/MWh, determined by the lower value of lost load and the loss of load probability.

For the interface constraint, the price is:

$$p_{\bar{r}_1} = v_1 (1 - F_1(\bar{r}_1 + r_1)) - v_0 (1 - F_0(r_0 - \bar{r}_1)) (1 - F_1(\bar{r}_1 + r_1)).$$

Figure 21

The maximal interface capacity scarcity price in Figure 21 is slightly over \$3,000/MWh, determined by the differences in the values of lost load and the loss of load probability.

Separable Demand Curve Approximation

In all cases, the price for reserves and the interface constraint are functions of all the reserve components. Furthermore, with constrained zones the relationships are not separable. One implication is that the scarcity prices are not simply additive, and the highest price in a region can never be higher than the value of lost load for that region. However, unlike the case of a single regional ORDC, the construction of the counterpart of $R_k(r_k)$ requires more than simply integrating under the prices along a single dimension.

A requirement to construct a counterpart of (1) is to have integrated functions $\hat{R}_k(r_o, \bar{r}_1, r_1)$ such that at the optimal solution $(r_o^*, \bar{r}_1^*, r_1^*)$ the derivatives equal the respective prices. For the single constrained zone and rest of the system, an example of a separable version of such a function would be:

$$\begin{aligned}
\hat{R}(r_0) &= \int_0^{r_0} p_{r_0}(x, \bar{r}_1^*, r_1^*) dx \\
\hat{R}(\bar{r}_1) &= \int_0^{\bar{r}_1} p_{\bar{r}_1}(r_0^*, x, r_1^*) dx \quad . \\
\hat{R}(r_1) &= \int_0^{r_1} p_{r_1}(r_0^*, \bar{r}_1^*, x) dx
\end{aligned}
\tag{19}$$

Implementation of these approximations utilizes a benchmark estimate of a reasonable version of the dispatch solution. The better the estimate, the better the approximation. Iteration on the estimate could be combined with the dispatch search algorithm in a manner that would implement the path model numerically without significant computation difficult.

At the equilibrium solution, the expected prices of reserves and interface constraints would satisfy the condition that $p_{r_i} = p_{r_0} + p_{\bar{r}_1}$. However, this is not true if separable demand curves employ a benchmark that is not equal to the equilibrium solution for the co-optimized dispatch. To address this property, an alternative approach would keep the separability assumptions in terms of intermediate variables, while enforcing the marginal condition for the relationship of the reserve and interface prices.

- A. Select a representative benchmark, $(r_0^*, \bar{r}_1^*, r_1^*)$.
- B. Use the ORDC model off-line to produce the initial “separable” approximations: $p_{r_0}(x, \bar{r}_1^*, r_1^*)$ and $p_{r_1}(r_0^*, \bar{r}_1^*, x)$.
- C. Construct a new variable $\Delta \bar{r}_1 = \bar{r}_1 - \bar{r}_1^*$, and these “incremental interface” variables are included in the energy co-optimization model along with the various reserve values.
- D. Implement the reserve component as the pricing model: $p_{r_0}(r_0 - \Delta \bar{r}_1, \bar{r}_1^*, r_1^*)$ and $p_{r_1}(r_0^*, \bar{r}_1^*, r_1 + \Delta \bar{r}_1)$.

In other words, the co-optimization objective function drops the explicit value for the interface constraint and constructs the values for the two types of reserves as:

$$\begin{aligned}
\hat{R}_0(r_0 - \Delta \bar{r}_1) &= \int_0^{r_0 - \Delta \bar{r}_1} p_{r_0}(x, \bar{r}_1^*, r_1^*) dx \\
\hat{R}_1(r_1 + \Delta \bar{r}_1) &= \int_0^{r_1 + \Delta \bar{r}_1} p_{r_1}(r_0^*, \bar{r}_1^*, x) dx \quad .
\end{aligned}
\tag{20}$$

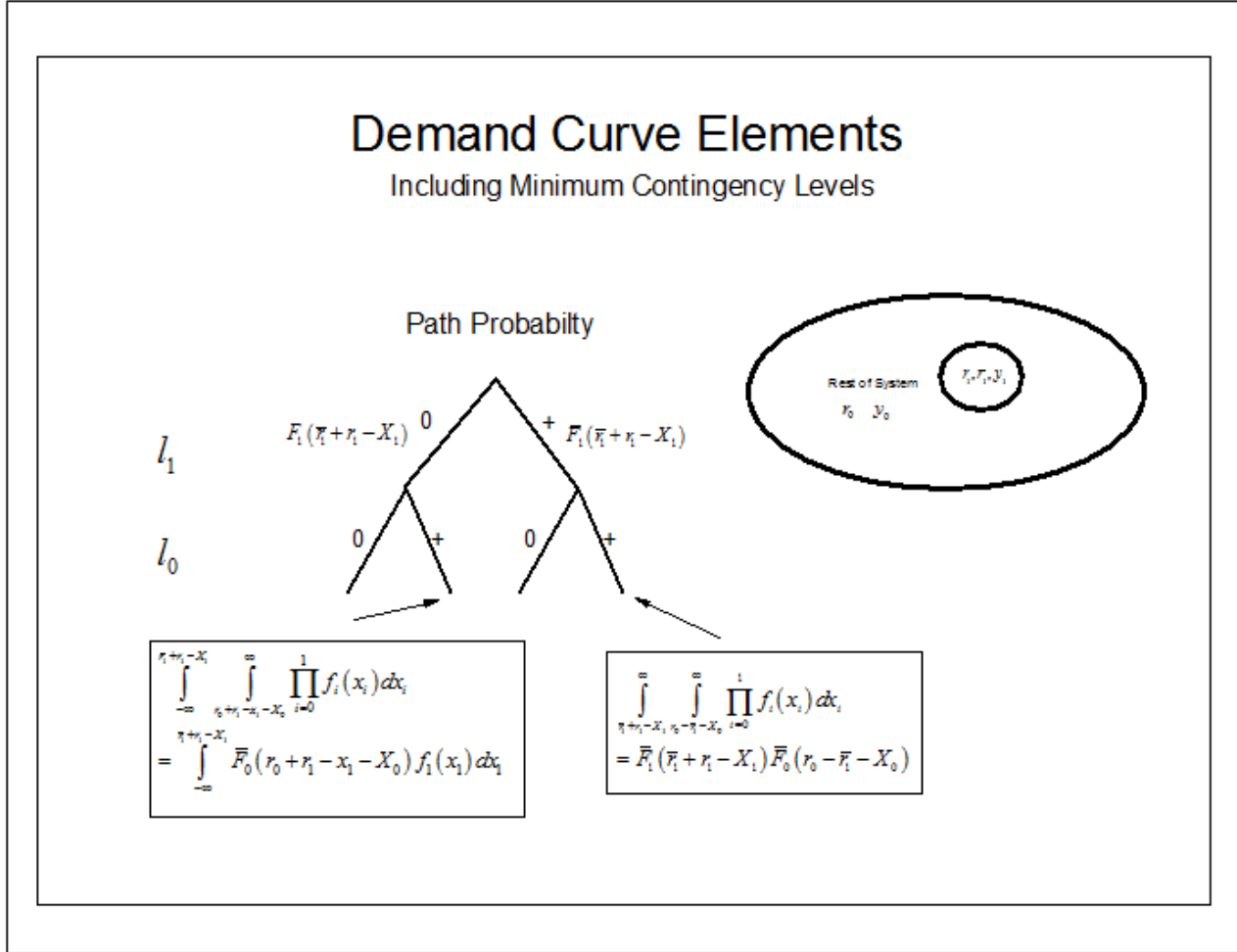
These approximate functions coincide with the reserve benefits when $\Delta \bar{r}_1 = 0$, and provide prices that imply an interface value equal to the difference of the constrained zone prices.

Zonal Contingency Requirements

The zonal demand curves would be modified to include minimum contingency requirements for emergency action such as a curtailment of load at the respective *VOLL*. The impact would be to change the path probability calculation to reflect the effect of the minimum contingency level.

For example, the revised version of the two critical path probabilities in Figure 13 would appear as in Figure 22.

Figure 22



This provides a calculation of the marginal values for ZEVUE with minimum contingency levels. The prices in the dispatch for these ex ante reserves will be the greater of the expected marginal value and the regional scarcity value v_i . In other words, the final price

$$p_{r_0} = \begin{cases} v_0 \int_{r_0 - \bar{r}_1}^{\infty} [1 - F_1(r_0 + r_1 - x_0)] f_0(x_0) dx_0, & \text{if } r_0 + r_1 \geq X_0 + X_1 \\ v_0, & \text{if } r_0 + r_1 < X_0 + X_1 \end{cases},$$

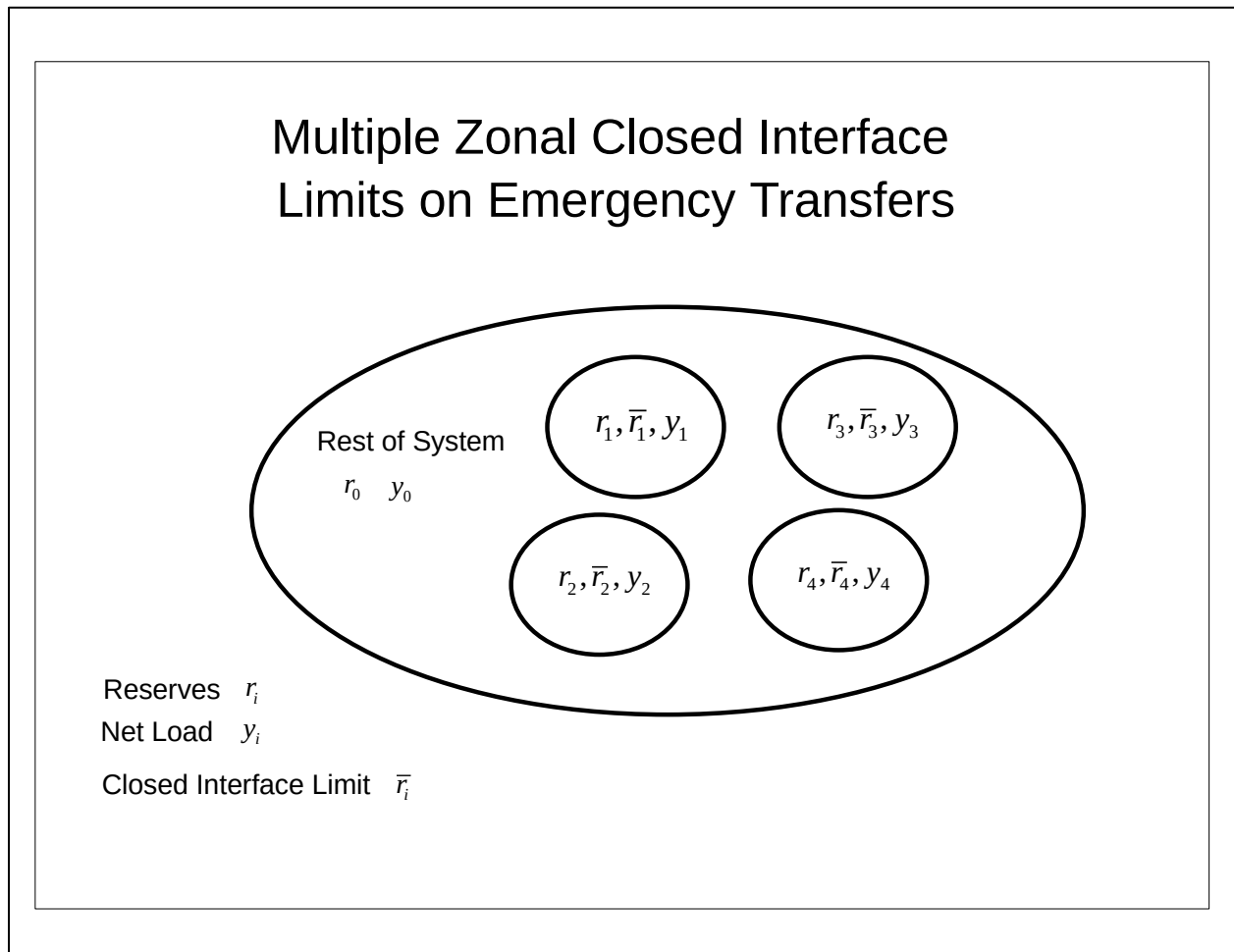
$$p_{r_1} = \begin{cases} v_1 (1 - F_1(\bar{r}_1 + r_1)) - v_0 (1 - F_0(r_0 - \bar{r}_1)) (1 - F_1(\bar{r}_1 + r_1)), & \text{if } \bar{r}_1 + r_1 \geq X_1 \\ v_1, & \text{if } \bar{r}_1 + r_1 < X_1 \end{cases}.$$

This method of incorporating the contingency minimum levels is a generalization of the simple shift of the ORDC in Figure 5.

Multiple Locations and Emergency Actions

The probability tree approach provides an analytical derivation of an ORDC. Adding more regions is straightforward. The associated probability tree grows, but the simplifying assumptions about relative values of loss load in regions preserve the basic structure of the tree.

Figure 23



Extension to include multiple types of emergency actions would require expansions of the event tree to incorporate different event combinations. In particular, the simple paths in the various probability trees arise because of the protocol that loss of load inside the constrained region takes precedence over that outside the region. If there are many emergency steps modeled, the optimization assumption could upset this protocol.

Adding multiple emergency actions within each zone is possible, but the relationships between the costs of emergency actions may allow some actions inside a constrained zone to be less costly than

actions in the rest of the system. Hence, the probability tree grows through introduction of more possible system states implying different binding constraints.

The underlying logic remains for calculation of ZEVUE as a function of all the reserve and interface levels. An alternative computational approach would apply Monte Carlo simulation to estimate the expected values of the prices of interest. A generalization of the ZEVUE with parallel constrained zones would incorporate multiple zones ($i = 0, \dots, n$), multiple emergency actions ($em_{ij}, j = 1, \dots, m_i$) with costs net of the marginal energy dispatch level defining scarcity as ($v_{ij}, j = 1, \dots, m_i$), and minimum contingency reserves (X_i). The constrained zones are all parallel to each other, as in Figure 23. The “rest of the system” is zone 0. The emergency action upper bound is infinite for the first emergency action type ($j = 1$) in each region, which is assumed to be the most expensive action in each region and represents involuntary load curtailment at the region’s net *VOLL*. The interface limits are on flows into constrained regions, but there is no limit modeled for the flows out of a constrained region.

Let:

- r_i : reserves , $i = 0, \dots, n$
- $\bar{r}_i$: available transfer limit , $i = 1, \dots, n$
- em_{ij} : emergency action , $i = 0, \dots, n; j = 1, \dots, m_i$
- v_{ij} : value of emergency action , $i = 0, \dots, n; j = 1, \dots, m_i$
- X_i : minimum required reserves , $i = 0, \dots, n$
- Kem_{ij} : maximum of emergency action , $i = 0, \dots, n; j = 1, \dots, m_i$
- $\hat{r}_i$: utilized reserves , $i = 0, \dots, n$
- $\hat{\bar{r}}_i$: utilized available transfer limit , $i = 1, \dots, n$
- y_i : realized net load change , $i = 1, \dots, n$

The zonal expected value of unserved energy is defined as before according to the program to minimize the cost of emergency action given each realization of a deviation in the net loads:

$$(21) \quad ZEVUE(r, \bar{r}) = E_y \left\{ \begin{array}{l} \text{Min}_{em, \hat{r}, \hat{\bar{r}} \geq 0} \sum_i \sum_j v_{ij} em_{ij} \\ \sum_i y_i - \sum_i \sum_j em_{ij} \leq \sum_i \hat{r}_i - \sum_i X_i \\ y_i - \sum_j em_{ij} \leq \hat{\bar{r}}_i + \hat{r}_i - X_i, \quad i = 1, \dots, n \\ em_{ij} \leq Kem_{ij}, \quad i = 0, \dots, n; j = 2, \dots, m_i \\ \hat{r} \leq r \quad : p_r \\ \hat{\bar{r}} \leq \bar{r} \quad : p_{\bar{r}} \end{array} \right\}$$

For any give realization of the random change in the net load (y) that must be met by reserves, the dual variables from the reserve availability constraints define the realized marginal value of operating reserves and reserve transfer limits, $p_r, p_{\bar{r}}$. The expected values of these prices define the loss-of-load probability estimates in (17) and (18). This corresponds as well to the loss-of-load probability derivation of the single region ORDC. A Monte Carlo application for the optimization provides an offline method to estimate the respective expected values.

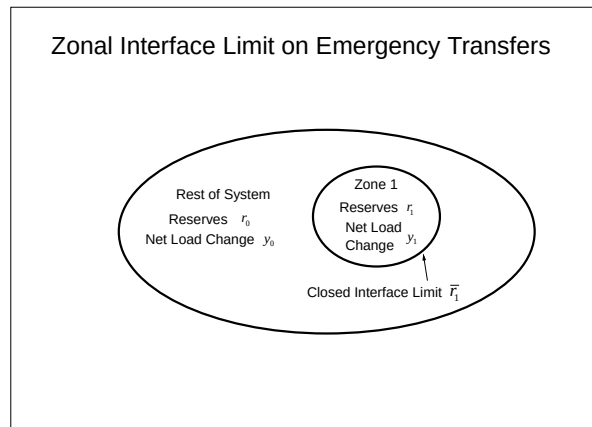
If the available reserves violate the minimum contingency levels ex ante, then emergency action would be needed to restore the reserves in the ex-ante dispatch. This corresponds to the minimum contingency step function derivation of the single region ORDC. The marginal value of this ex ante minimum condition can be solved by solving the value of unserved energy problem (21) with the load deviation set to zero ($y = 0$).

The resulting operating reserves values for the ORDC is the maximum of each of the two estimated reserve prices for each type of reserve. The marginal value of the interface capacity is the difference in the respective reserve prices.

The example in Figure 19 to Figure 21 illustrates an estimated ORDC with one constrained zone and only one type of emergency action. The parameter assumptions and an assumed benchmark provide the components for the approximation.

	ROS	Zone
Expected Total (MW)	107.1	45.90
Std. Dev (MW)	488.99	209.57
VOLL (\$/MWh)	7000	10000

	ROS	Zone 1	Interface
Benchmark (MW)	160.65	68.85	45.90



Using the same input assumptions, the Monte Carlo replication produces prices at the benchmark as:

	ROS	Zone 1	Interface
Benchmark (MW)	2808	5245	2437

These are consistent with corresponding values estimated from the probability tree in Figure 19 to Figure 21.

As with the probability tree, the implied ORDC is multivalued, with the changing values of all of the elements affecting all the reserve prices. A separable approximation for the combined energy-reserve dispatch model (1) would apply integrated functions such that at the optimal solution $(r_0^*, \bar{r}_1^*, r_1^*)$ the derivatives equal the respective prices. For the single constrained zone and rest of the system, an example of a separable version of such a function would be as in (20).

This approach requires an estimate of the reserve solution, and each of the separable functions in (20) depends on all the elements of the benchmark reserve estimate. With a good benchmark estimate, the separable reserve value functions would provide a good approximation. If necessary, the reserve solution from the dispatch model would update the benchmark estimate as part of the iterative solution of the combined energy and reserve dispatch model.

Co-Optimization with Locational Demand Curves and Interface Constraints

The design of the ORDC allows for co-optimization with the energy dispatch. A modified version of the dispatch co-optimization problem in (1) would include these reserve functions in the objective and add a constraint that captures the interaction of energy and reserves in the locational transfer limit.

Extending this to incorporate different types of reserves, such as responsive and non-spin, with the corresponding approximation of separable reserve value functions, allows for simultaneous dispatch of energy and reserves. The constrained zone interface limit ($Kint_i$) must accommodate both the energy flow into the constrained needed to meet the net load ($i' \hat{y}_i$) and the reservation for operating reserves ($\bar{r}_i$). With these additions, a representative version of the combined dispatch model becomes:

$$\begin{aligned}
& \text{Max} \quad B(d) - C_R(g_R) - C_{NR}(g_{NR}) + \sum_{i=0}^n \left[R_{li}(\hat{r}_{Ri}^z) + R_{Ni}(\hat{r}_{NSi}^z) \right] - \sum_i \sum_j v_{ij} em_{ij} \\
& d, g_R, g_{NR}, r_R^z, r_{NR}^z, r_{NS}^z, em \geq 0; \\
& \hat{r}_R^z, \hat{r}_{NR}^z, \hat{r}_{NS}^z, \Delta \bar{r}, \hat{y}
\end{aligned}$$

$d - g_R - g_{NR} = \hat{y}$	Net Loads	ρ
$i^t \hat{y} = 0$	Load Balance	λ
$H\hat{y} \leq b$	Transmission Limits	μ
$g_R + r_R \leq K_R$	Responsive Capacity	θ_R
$g_{NR} \leq K_{NR}$	Generation Only Capacity	θ_{NR}
$r_{NSi} \leq K_{NSi}$	Non-Spin Capacity	θ_{NS}
$i^t r_{Ri} = r_{Ri}^z$	Zonal Responsive Reserves	γ_R
$i^t r_{Ri} + i^t r_{NSi} = r_{NSi}^z$	Zonal Non-Spin Reserves	γ_{NS}
$r_R \leq r_R^{\max}$	Responsive Ramp Limit	η_R
$r_{NS} \leq r_{NS}^{\max}$	Non-Spin Ramp Limit	η_{NS}
$i^t \tilde{y}_i + \bar{r}_i \leq K \text{int}_i$	Zonal Interface Limit, $i > 0$	$\gamma_{K \text{int}_i}$
$\bar{r}_i^* + \Delta \bar{r}_i = \bar{r}_i$	Zonal Reserve Interface, $i > 0$	$\gamma_{\bar{r}_i}$
$r_{R0}^z - \sum_{i=1}^n \Delta \bar{r}_i = \hat{r}_{R0}^z$	Adjusted Responsive Reserves	ω_{R0}
$r_{Ri}^z + \Delta \bar{r}_i = \hat{r}_{Ri}^z$	Adjusted Responsive Reserves, $i > 0$	ω_{Ri}
$r_{NS0}^z - \sum_{i=1}^n \Delta \bar{r}_i = \hat{r}_{NS0}^z$	Adjusted Non-Spin Reserves	ω_{NS0}
$r_{NSi}^z + \Delta \bar{r}_i = \hat{r}_{NSi}^z$	Adjusted Non-Spin Reserves, $i > 0$	ω_{NSi}
$-\sum_{i=0}^n \sum_{j=1}^m em_{ij} \leq \sum_{i=0}^n r_{Ri}^z - \sum_{i=0}^n X_i$	System Contingency Minimum	ϕ_S
$\sum_{j=1}^m em_{ij} \leq \bar{r}_i + r_i - X_i,$	Zonal Contingency Minimum, $i > 0$	ϕ_i
$em_{ij} \leq K em_{ij}$	Emergency Action Limits,	κ_{ij} .

The result of co-optimization of reserves and energy would induce scarcity prices for reserves and the interface constraint that affect the locational price of energy.

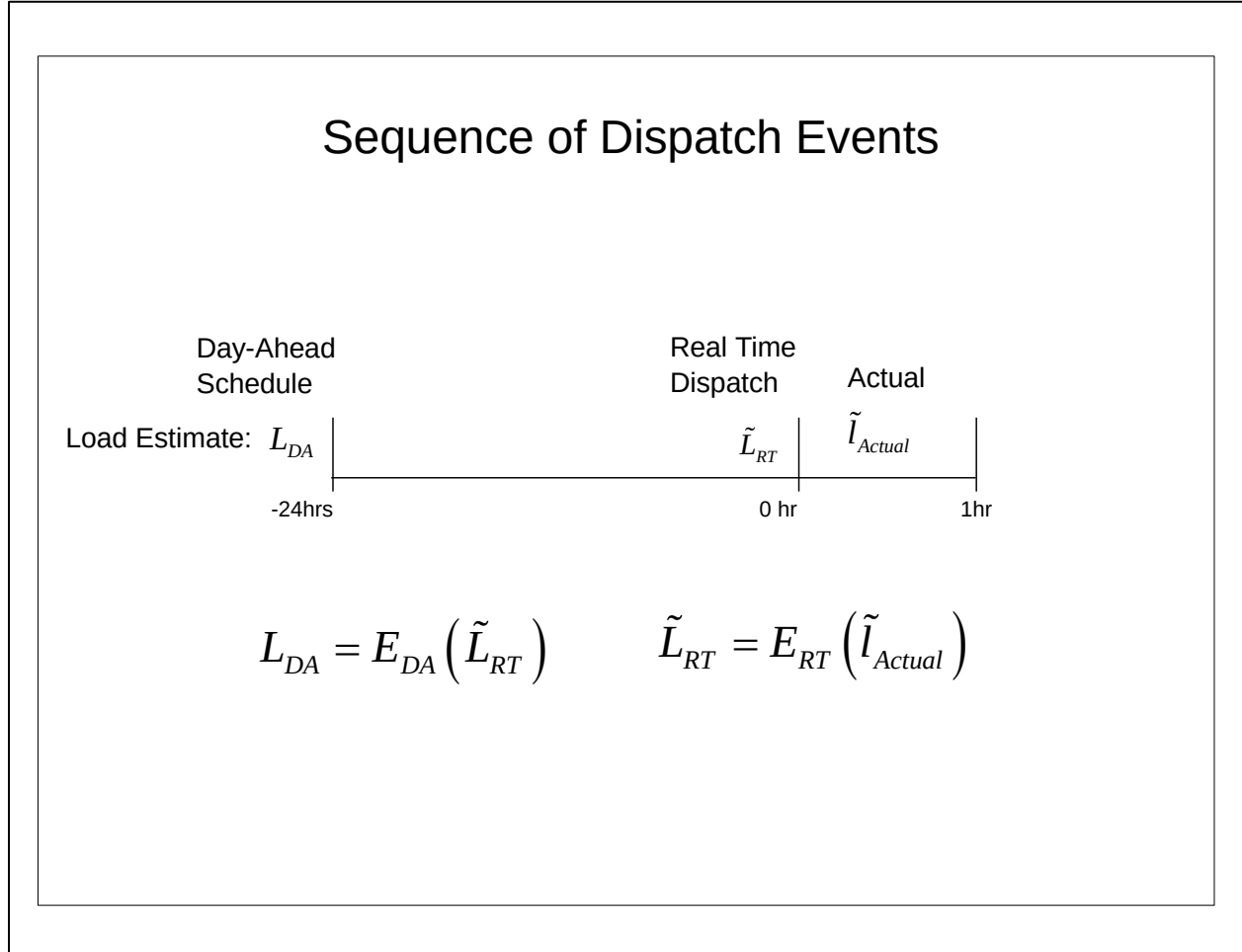
Day-Ahead ORDC

A real-time ORDC with reserve products provides a workable approximation of scarcity pricing and incentives for efficient operation. The basic model extends to forward markets where generation, load and reserves create forward commitments and there is a multi-settlement resolution of these forward financial obligations and imbalances. Extension of the ORDC to the forward market includes elements that are similar to but not identical with the application of the

ORDC in the real-time market. The case of a day-ahead market coupled with a real-time market illustrates derivation of a day-ahead ORDC from the underlying principles.

The timeline in Figure 24 provides the connections with the main variables to support differences in expectations of uncertainty from the perspective of the real-time dispatch versus 24-hours ahead at the time of the day-ahead scheduling.

Figure 24



The actual load is defined as $\tilde{I}_{Actual}$, which will be observed over the actual dispatch interval, taken here for illustrative purposes to be one hour. Just before the start of the dispatch interval, shown as hour 0, the system operator sets a dispatch schedule L_{RT} . The actual load is not known at the time of this real-time dispatch decision. For illustrative purposes, assume that the dispatch is set at the expected value of the actual load given the available information at the start of the real-time interval, so in real-time dispatch we have:

$$L_{RT} = E_{RT} \left(\tilde{I}_{Actual} \right).$$

The actual net load changes over the dispatch period. These changes can be deviations in load and the full range of deviations of dispatch generation, all interpreted as an uncertain change in net load that must be met by reserves or emergency action. The real-time ORDC defines the marginal willingness-to-pay for an increment of reserves. If we have real-time reserves of r_{RT} , then the focus is on the deviation $\tilde{I}_{Actual} - L_{RT}$. Given the real time reserves, the loss of load probability is:

$$(23) \quad Lolp_{RT}(r_{RT}) = Prob_{RT}(\tilde{I}_{Actual} - L_{RT} - r_{RT} \geq 0 | r_{RT}).$$

This is used to define the real-time ORDC.

Although L_{RT} is set at the time of the real-time dispatch, it is a random variable from the perspective of the day-ahead schedule, denoted as $\tilde{L}_{RT}$. The same could be true for the real-time reserves, $\tilde{r}_{RT}$, as seen from the day-ahead scheduling.

The day-ahead schedule L_{DA} is set at time -24 hours, where the illustrative schedule is set to the expected value of the real-time dispatch based on the information available day-ahead. Hence,

$$L_{DA} = E_{DA}(\tilde{L}_{RT}).$$

The day-ahead scheduling decision faces these uncertain variables, and other complications such as lumpy commitment decisions. For the sake of the present discussion, the assumption here is that all day-ahead variables are continuous and thus the focus is on the marginal conditions. But these day-ahead commitment decisions retain the property that they are inflexible in the sense that the decision must be made in the day-ahead schedule, otherwise the associated generation or reserve capacity would not be available in real-time.

In real-time it is natural to assume that the controllable capacity is inflexible in the sense that it must be obtained prior to its use, and before the uncertainty is revealed. The real-time capacity is all physical and there are no strictly financial or “virtual” elements in real-time. These are underlying assumptions of the design of the real-time ORDC.

In the day-ahead setting, the situation differs. There is some capacity that is inflexible in the sense that it requires a day-ahead physical commitment. But other capacity is flexible in that it can be dispatched in real-time without requiring a day-ahead commitment decision. In addition, there can be virtual transactions that are not connected to a physical schedule or dispatch.

Another complication of the day-ahead falls under the rubric of “reliability unit commitment,” (RUC) taken here to represent additional and separate commitment decisions that are not necessarily implicated by the bid-in load. For example, RUC commitments may be used to deal

with special transmission contingency issues outside the day-ahead model, or to allow for conservative operator load forecasts that differ from the bid-in load.

The treatment of RUC commitments and virtual transactions is set aside here to focus on the marginal value of “physical” commitments, including those for reserves, as part of the economic solution given day-ahead loads bids and generation offers. The discussion considers first the case of a single reserve product, and then introduces the case of more than one reserve product. Again, the approach is to approximate the marginal benefits of the underlying stochastic, dynamic optimization that is too hard to implement.

One Reserve Product

In the simplest case, where there is only reserve product, r_{DA} , the day-ahead ORDC would be defined by the willingness-to-pay for an increment of these day-ahead reserves. The analysis is similar to the real-time problem of finding a workable approximation without requiring explicit solution of the full dynamic, stochastic optimization problem.

In the approach here, there is a simplifying choice in the treatment of the day-ahead reserve schedules and the interaction with the changing load and dispatch in real-time. The range would be between no interaction and strong interaction.

With a single type of reserves, the strong interaction assumption would be that changes in load and associated generation in the real-time dispatch would imply a corresponding change between the day-ahead reserve schedule and the real-time reserves. Hence, the reserve in real-time, $\tilde{r}_{RT}$, would follow as:

$$(24) \quad \tilde{r}_{RT} = r_{DA} + (L_{DA} - \tilde{L}_{RT}).$$

From the perspective of the day-ahead, the real-time dispatch is uncertain, and hence the real-time reserves are uncertain. Therefore, the marginal value of real-time reserves, derived using (23) but seen from the day-ahead perspective, is uncertain. The *Lolp* expected value depends in part on the uncertainty between day-ahead and real-time. The marginal event is still seen as the need to revert to emergency actions during the actual dispatch. The focus remains on the use of reserves and the probability of the event of reverting to emergency actions, as in:

$$\tilde{I}_{Actual} - \tilde{L}_{RT} \geq \tilde{r}_{RT}.$$

The strong interaction assumption provides the probability of this occurrence by connecting the day-ahead and the real-time. In particular, assuming (24) holds, we have:

$$(25) \quad \tilde{I}_{Actual} - \tilde{L}_{RT} - \tilde{r}_{RT} = \tilde{I}_{Actual} - \tilde{L}_{RT} - r_{DA} - (L_{DA} - \tilde{L}_{RT}) = \tilde{I}_{Actual} - L_{DA} - r_{DA}.$$

From the perspective of the day-ahead conditions, the real-time emergency action condition is:

$$\tilde{I}_{Actual} - \tilde{L}_{RT} - \tilde{r}_{RT} \geq 0.$$

This includes random variables from the perspective of the day-ahead decisions. However, using (25) this is equivalent to:

$$\tilde{I}_{Actual} - L_{DA} - r_{DA} \geq 0.$$

Therefore, the relevant loss of load probability for defining the marginal value of reserves scheduled day-ahead is:

$$(26) \quad Lolp_{DA}(r_{DA}) = Prob_{DA}(\tilde{I}_{Actual} - L_{DA} - r_{DA} \geq 0 | r_{DA}).$$

This loss-of-load probability would be used with the *VOLL* and any threshold minimum contingency reserve requirements to define the day-ahead ORDC using the same analysis and approximations as the real-time ORDC, but with the different probability distribution.

By way of comparison, the case of no interaction would be relevant with multiple reserve products.

Multiple Reserve Products

The strong interaction assumption between day-ahead reserve schedules and real-time changes in net load may not be appropriate when there are multiple reserve products. For instance, with two reserve products, say responsive and non-spin as above with (r_R, r_{NS}) , an alternative assumption would be that the total of the two types of reserves would follow the strong interaction assumption, but the higher quality r_R reserves would have no interaction required by any physical constraint. In effect, the assumption is that the random variation between day-ahead and real-time is absorbed by the lower quality reserves, r_{NS} . With the added assumption that there is an interior solution, so that $r_{NS} > 0$, the marginal conditions for the lower quality reserves must account for the uncertain interactions over the day, but the higher quality reserves would be preserved and require a *Lolp* contribution calculation based only on real-time uncertainty.

Hence, the no interaction assumption replaces (24) for the responsive reserves and maintains that:

$$(27) \quad \begin{aligned} \tilde{r}_{NS,RT} &= r_{NS,DA} + (L_{DA} - \tilde{L}_{RT}) \\ r_{R,RT} &= r_{R,DA}. \end{aligned}$$

From this perspective, the analysis of the corresponding loss-of-load probabilities would be different for the two types of reserves. The non-spin type reserve would be valued based on the

day-ahead probability distribution as in (26). The responsive reserve contribution to the total reserve price would be valued using the real-time probability distribution as in (23).

Hence, following the approach in (16), with the *VOLL* approach for multiple reserves types to define the day-ahead reserve prices, the sub-period *Lolp* relevant for each type of reserve product would be different for the responsive and non-spin reserves, and based on the real-time or day-ahead *Lolp* as in:

$$\begin{aligned}
 \pi_{R,DA}(r_{R,DA}) &= \begin{cases} Lolp_{I,RT}(i^t r_{R,DA} - X), & i^t r_{R,DA} - X \geq 0 \\ 1, & i^t r_{R,DA} - X < 0 \end{cases} \\
 \pi_{NS,DA}(r_{R,DA}, r_{NS,DA}) &= \begin{cases} Lolp_{I+II,DA}(i^t r_{R,DA} + i^t r_{NS,DA} - X), & i^t r_{R,DA} + i^t r_{NS,DA} - X \geq 0 \\ 1, & i^t r_{R,DA} + i^t r_{NS,DA} - X < 0 \end{cases} \\
 P_{R,DA}(r_{R,DA}, r_{NS,DA}) &= v * (\delta * \pi_{R,DA}(r_{R,DA}) + (1 - \delta) * \pi_{NS,DA}(r_{R,DA}, r_{NS,DA})), \\
 P_{NS,DA}(r_{R,DA}, r_{NS,DA}) &= v * (1 - \delta) * \pi_{NS,DA}(r_{R,DA}, r_{NS,DA}).
 \end{aligned}
 \tag{28}$$

In principle, if reserves did not interact with generation and load changes, so that the available reserves in real-time would not be affected by uncertainty, everything would reduce to the case of day-ahead prices being determined solely by the real-time *Lolp*. This special case would be the same result that would obtained from (28) if there were no uncertainty between day-ahead scheduling and real-time dispatch.

The cascade structure of (28) ensures that the day-ahead price of the higher quality reserve is greater than the price of the lower quality reserve, and the difference in prices reflects only the fast response benefit that appears in real time and is not affected by the uncertainty between day-ahead and real-time.

The true uncertain environment of the stochastic, dynamic optimization would fall somewhere between the assumptions of strong interaction and no interaction. A reasonable choice between the day-ahead and real-time probability distributions would depend in part on an estimation of the strength of the interaction effect.

Day-Ahead and Real-Time Settlements with an ORDC

An ORDC in the day-ahead and real-time gives rise to energy and reserve imbalance charges (Hogan, 2013). There are several issues, but here the focus is on how the payments should work in the case of examples where market-clearing energy offers are at the value of lost load (*VOLL*). This is an extreme case, but the discussion clarifies the approximations in the ORDC and the interactions between day-ahead and real-time settlements. Does this necessarily give rise to a double payment above *VOLL*? Is it necessary to use the day-ahead prices in determining the real-time settlements? The answers discussed below are “no on average” and “no.”

The issue is closely related to what has been described as “discounting” in the ORDC, where the implicit scarcity price is defined by the net value,

$$v = (VOLL - \partial \hat{C}_R(\hat{g}_R)) = (VOLL - \text{marginal energy offer}),$$

combined with the *Lolp*. Hence, the scarcity price is $v^* Lolp$. The discounted value applies for the energy offers from the marginal plants in the dispatch. In constructing the ORDC, this implies that with sufficiently high energy offers, at the *VOLL*, the implicit value of scarcity (of the marginal dispatched capacity) is zero. The discussion below describes an approach that integrates this idea with a settlements process. The examples are for a single ORDC and one type of reserves, but the same issues appear in the interacting zonal ORDC models.

Two-Settlement Model

The concern with examples that show apparently anomalous results when there are very high energy offers is not something that appears to have arisen in other applications of ORDCs. For example this concern could have arisen in the New York Independent System Operator (NYISO) although the scarcity values in an earlier version the NYISO model were low (max about \$1800/MWh), along with a low energy offer cap (\$1000/MWh). This means that the combined price never approaches the *VOLL*. However, if the NYISO model were applied without these low offer caps, the energy price could be driven to $2*VOLL$. In fact, with the additive regional zonal model for reserves, the limit in principle could be $3*VOLL$.

A principal reason for offer caps is to mitigate market power, and as a safety valve to avoid unforeseen consequences that produce unbounded prices. For these purposes, there is no need for any link between the offer cap and the *VOLL*. All that is required is that the offer cap be above the true variable generation costs. Furthermore, for a generator without market power, the uniform equilibrium price with an ORDC provides a strong incentive to offer energy at variable cost. The generator does not need to offer high in order to capture a scarcity rent. In general, we would expect $VOLL > Offer\ Cap$, but this is not required and in some cases there could be a high offer for generation that could provide both energy and reserves. (There could also be high energy offers for generation capacity that does not provide reserves, but this would be easy to accommodate and is ignored in the illustrations). The market design does not assume low energy offers, and the example here shows how high energy offers affect the outcomes.

Equilibrium Prices

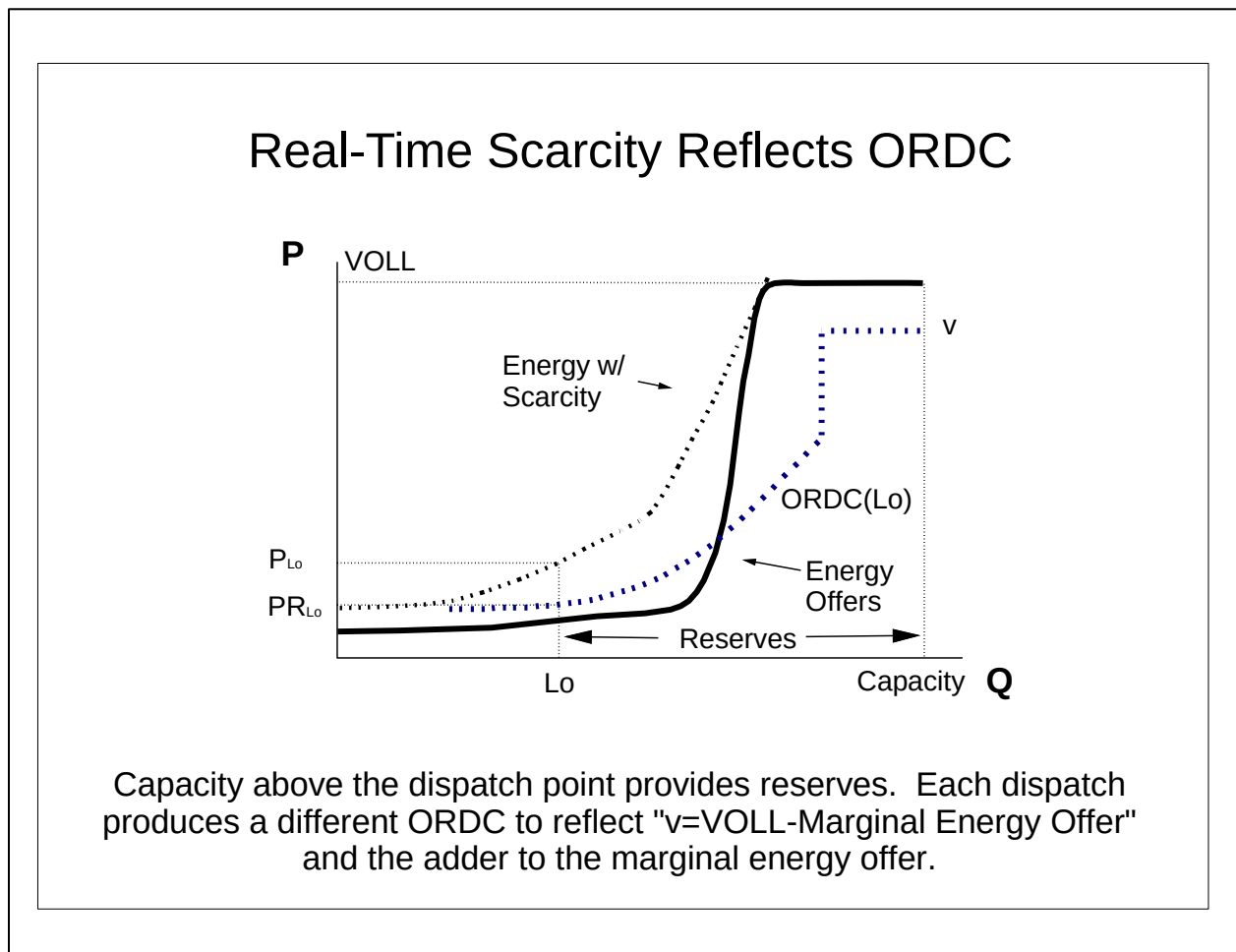
There are many moving pieces. The illustration here uses simple graphics with continuous functions, only one type of reserves, and market participants who are acting like risk-neutral competitive generators and loads that do not manipulate the markets or prices.

The presentation uses an equilibrium formulation, with uncertainty about the real time outcomes when the day-ahead market clears. The design features include that there is no arbitrage at the

margin in the equilibrium solution. Hence, at the margin, no generator has an incentive to deviate from the dispatch of energy and reserves. Further, the day-ahead equilibrium prices are equal to the expected value of the real-time prices for energy and reserves. Virtual bids and offers in the day-ahead market are then settled at the real-time price. For simplicity, the physical loads and generators are treated as hedgers who bid for expected demand and offer the full generation available. Virtual bidders are all alike and assumed to be risk neutral and not liquidity constrained. This assumption for virtual trading implies a horizontal virtual offer curve day-ahead at the expected real-time prices.

In order to focus on the impact of very high energy offers, the illustration in Figure 25 assumes that there is a very nonlinear generation offer curve that caps out at the *VOLL*. There are multiple dimensions to this problem: the energy quantity is measured from left to right; physical reserves are measured from right to left; there is a different ORDC for every energy dispatch, but the figure shows only the ORDC for the given dispatch.

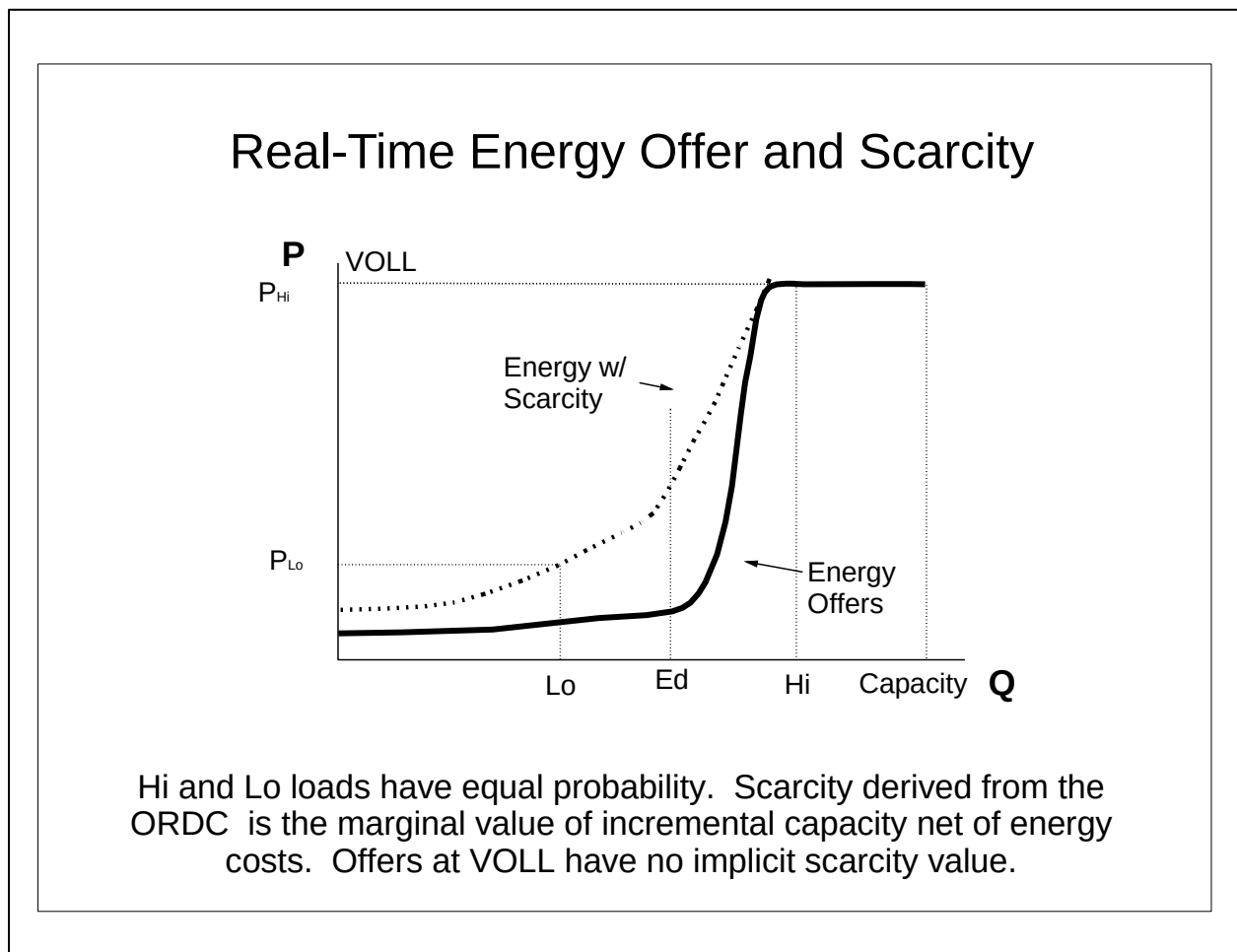
Figure 25



At the real-time “Lo” level of load in Figure 25, energy is dispatched to meet load and the remaining capacity is treated as reserves. The ORDC superimposed on the reserves determines the scarcity adder $\nu * Lolp$ to the marginal energy offer at the “Lo” quantity, and the total determines the energy price. For each dispatch, there is a different value of ν to reflect the changing marginal energy offer. The dashed line traces out the resulting combination of “energy with scarcity” price. If the dispatch load is high enough, the energy offer is at the *VOLL* and there is no scarcity adder for this marginal capacity. This real-time dispatch always leaves the marginal generator indifferent between providing energy and providing reserves.

In Figure 26 the illustration sets out two possible outcomes in the real time dispatch. To simplify, assume that there are two load levels, “Lo” and “Hi,” that are equally probable.

Figure 26

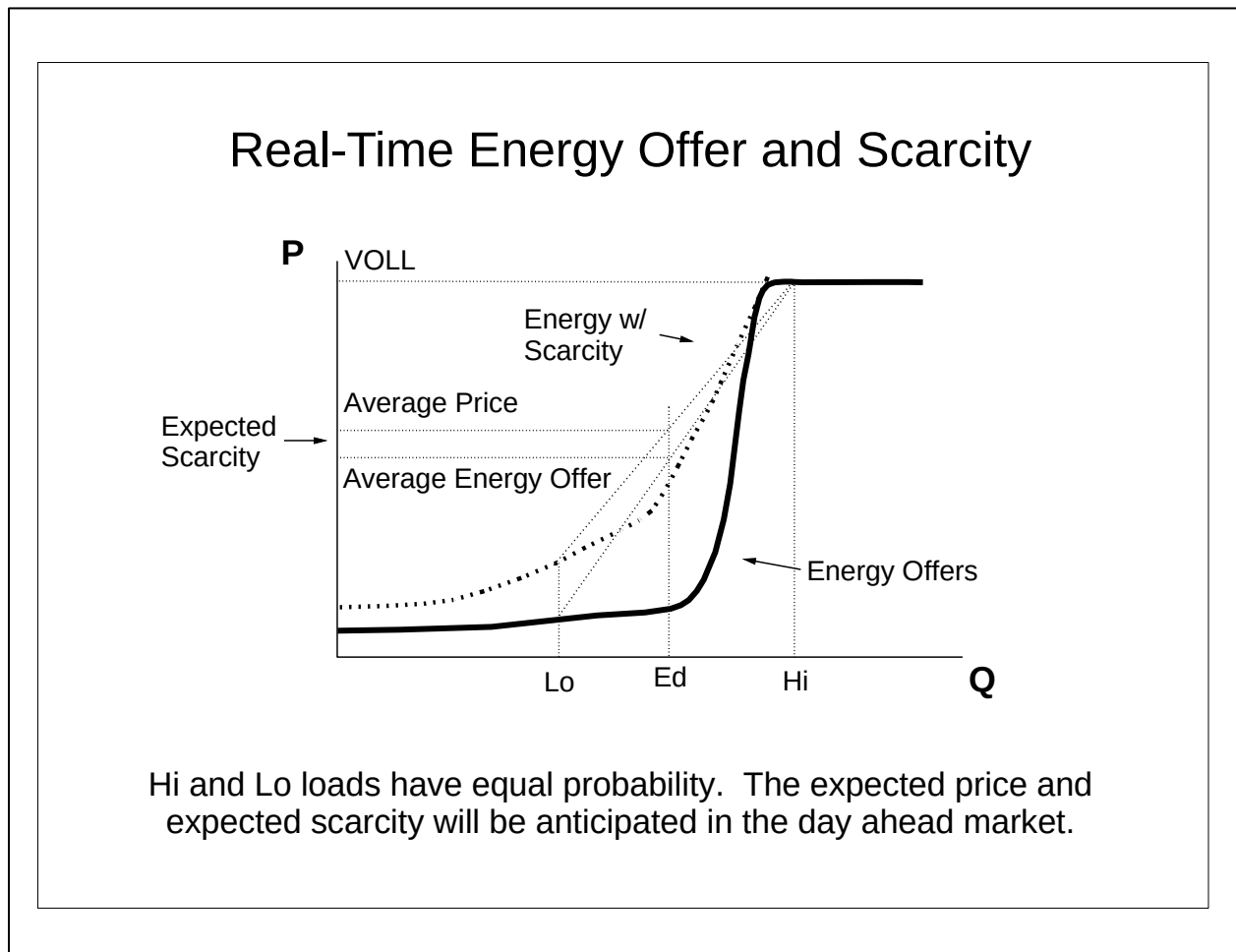


The expected value of demand or average load is “Ed.” When there is Lo load the dispatch produces an energy price that includes a positive scarcity adder. When the load is Hi, the dispatch produces a high energy price at the *VOLL*, but there is no scarcity adder and the ORDC(Hi) is just

the zero axis. The expected load at E_d is never realized in real time, but it will be relevant in the day-ahead schedules.

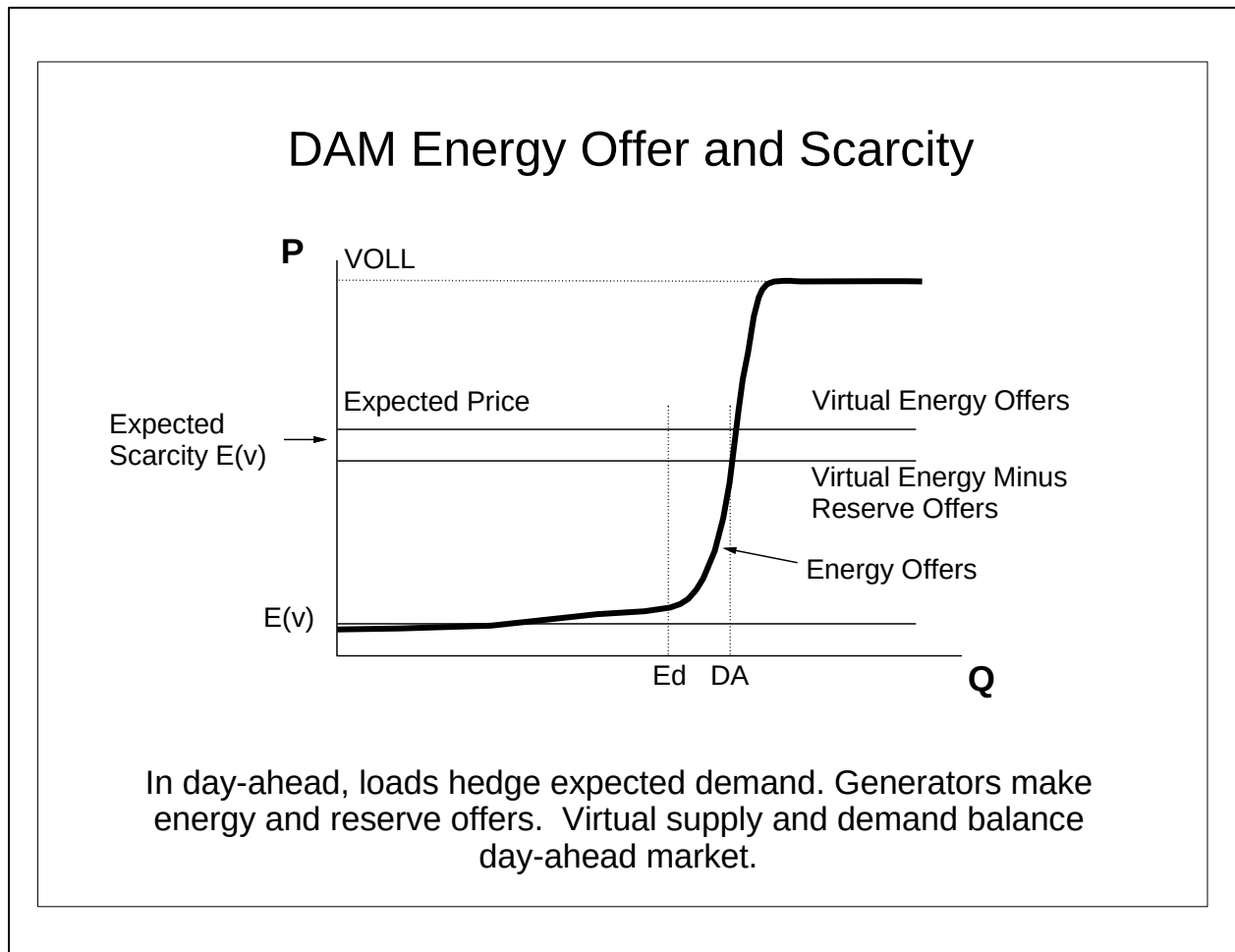
The illustration in Figure 27 takes this input and illustrates the average energy price, the average energy offer, and the difference between these two which is the average scarcity price.

Figure 27



These average prices deviate significantly from the energy offers and scarcity prices that would apply in real time at the average load. This arises from the non-linear generation offer curve and the assumption that the Lo and Hi values are materially different. In actual application the real-time range could be relatively small, and the offer and scarcity curves would be approximately linear. However, the extreme case in Figure 27 is useful in illustrating the connections with the day-ahead market and the large variation in the real-time outcomes.

In Figure 28 the illustration summarizes the day-ahead market with expected load and energy offers to hedge physical generation, and virtual offers and bids that will be cleared at the real-time prices.

Figure 28

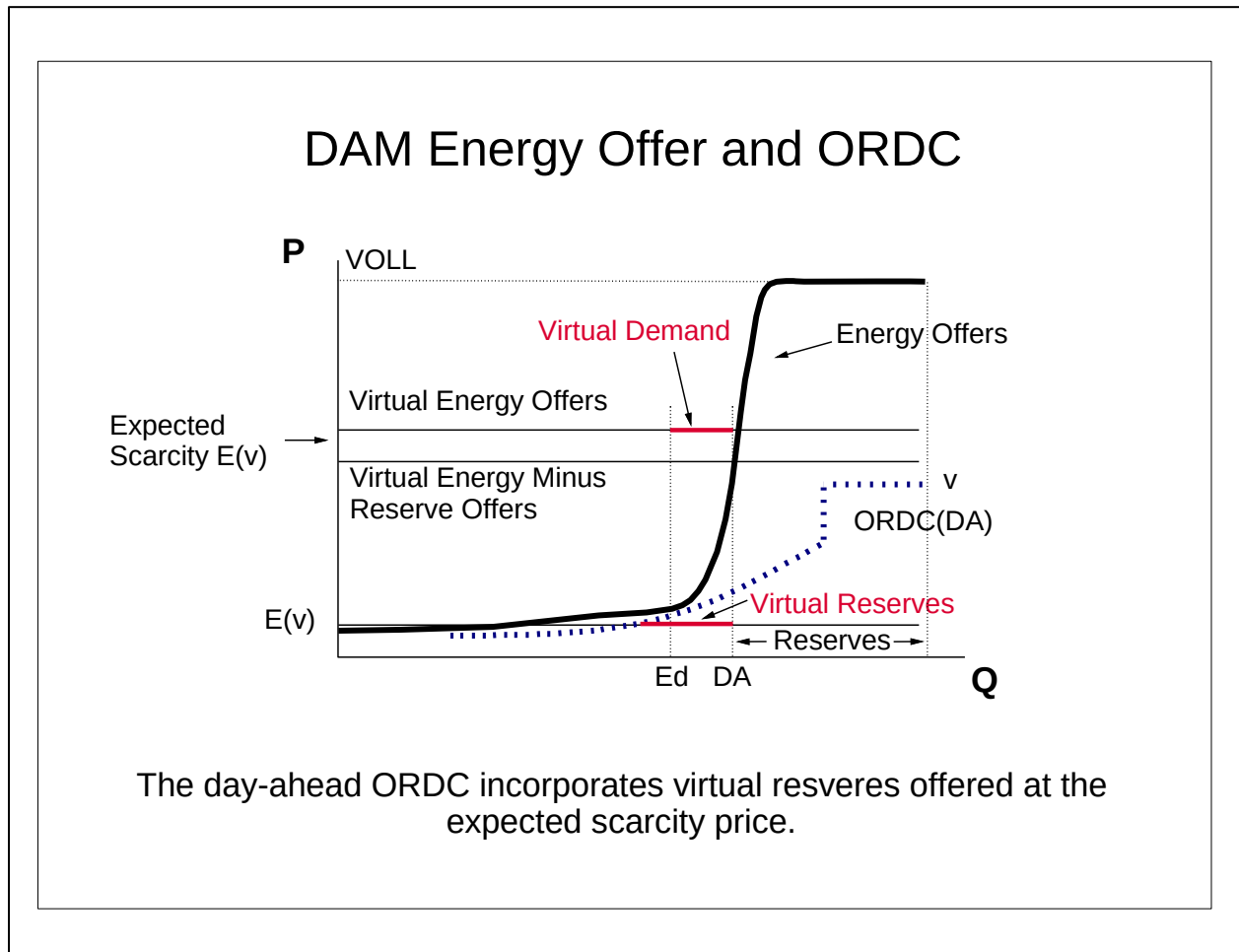
The assumption is that load hedges the expected value of real-time load, E_d . Generators make offers that are at the same offer costs as the real-time. The equilibrium conditions, identical information, and risk neutrality assumptions imply that the virtual offers and bids day-ahead are at the expected real-time prices.

The day-ahead ORDC reflects the expected conditions, bids and offers. In this case, the difference between the day-ahead energy dispatch, DA , and the expected real-time load, E_d , arises from the cleared virtual demand bids. The dispatch of energy at DA implies a marginal energy cost that is higher than the Lo value and lower than the Hi value from real time. As shown in Figure 29, this produces a value of v and results in an ORDC that includes positive scarcity prices but with a lower implicit scarcity adder than the ORDC illustrated in Figure 25 for the real-time Lo case. Furthermore, virtual offers for reserves can shift the ORDC, and both effects result in an equilibrium scarcity price that equals the expected value of the real-time scarcity adder.

To simplify the illustration, the day-ahead ORDC applies the case with no interaction between day-ahead schedule and real-time dispatch in affecting the availability of the real-time reserve.

Hence, the day-ahead ORDC uses the same *Lolp* as the real-time ORDC. The more general case would not affect the main conclusions here.

Figure 29



The illustration in Figure 29 indicates how the day-ahead ORDC is affected by the virtual offers and remains consistent with the basic model, counting the virtual reserves as part of the reserve supply, in addition to the “physical” reserves provided by the difference between day-ahead dispatch of physical energy and physical capacity.

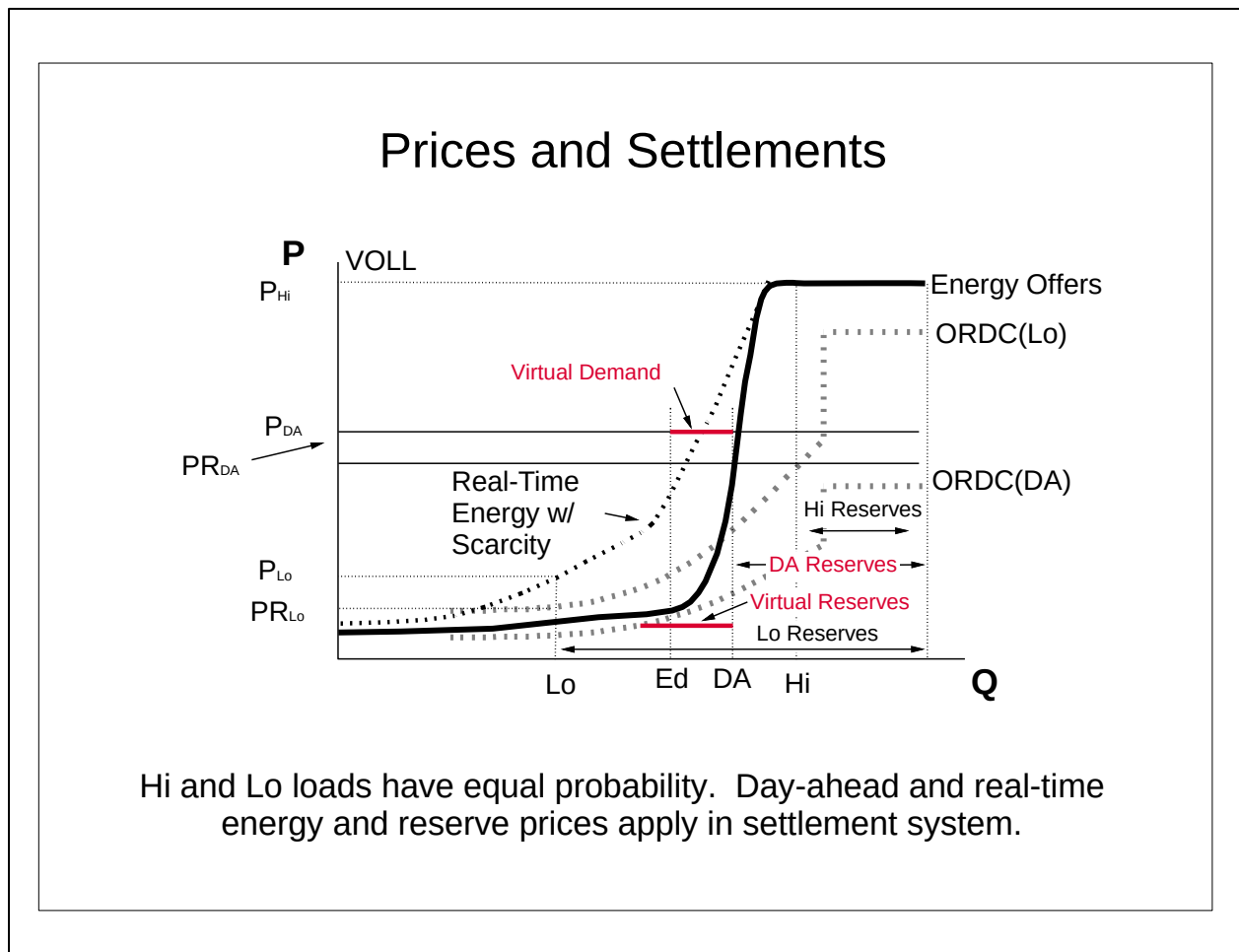
The assumption of the same generation offers in day-ahead and real-time simplifies the presentation and illustrates the various component transactions. The more realistic case, with inflexible generators that need a day-ahead commitment decision would imply a more elastic offer curve day-ahead. In addition, the choice of different probability distributions for the day-ahead and real-time ORDCs would change the graphics somewhat but would not affect the basic settlements logic. The assumed presence of virtual transactions day-ahead would assure the equilibration of the day-ahead and expected real-time prices for energy and reserves.

Settlements

One perspective for describing the day-ahead and real-time settlements is that all cleared transactions in the day-ahead market are financial obligations, not just the virtuals. This is sometimes referred to the “gross pool” approach. The results would be the same as for the “net pool” approach where we net out real-time deliveries relative to day-ahead schedules and make settlement payments only for the imbalances. However, the gross pool interpretation is more direct because we avoid the necessity of doing the accounting to net out the imbalances between day-ahead schedules and real-time deliveries.

The cleared prices for the day-ahead are shown in Figure 30. In the first settlement the day-ahead awards are paid or pay for the cleared quantities at the day-ahead prices. In the second settlement, one of the load conditions appears in real time, either Lo or Hi, and we see the appropriate corresponding real-time prices in Figure 30. In the gross pool interpretation, all the day-ahead schedules are purchased back at the real-time prices, and all the real-time physical transactions are settled at the real-time prices.

Figure 30



For energy transaction cleared in the day-ahead, the real-time price is either P_{Lo} or P_{Hi} . The revenues day-ahead are determined by P_{DA} . Hence, under the gross pool, the net payment is either $P_{DA} - P_{Lo}$ or $P_{DA} - P_{Hi}$. The difference may be positive or negative, but on average the payment is $P_{DA} - 0.5P_{Lo} - 0.5P_{Hi} = 0$, and the equilibrium has zero net profit. A similar result applies for the payments for reserves.

In real time, the physical dispatch applies the usual rules and results of economic dispatch. The gross payments for the physical dispatch in real time reflect the efficient economic solution, and have the standard incentive properties.

When viewed from a net pool perspective, for a particular real-time dispatch, the payments may include a “double” amount. For example, if a generator clears to provide reserves in the day-ahead at price PR_{DA} , and the real-time outcome is the Hi case with the generator providing energy, the generator receives $(PR_{DA} - 0)q + P_{Hi}q = (PR_{DA} + VOLL)q$. This is a type of “double” payment, but it is not a problem. In the alternative case, where the generator is not dispatched but provides reserves at the Lo load, then the payment is $(PR_{DA} - PR_{Lo})q + PR_{Lo}q = PR_{DA}q$. The average payment across the two real-time outcomes is:

$$0.5(PR_{DA} + VOLL)q + 0.5*PR_{DA}q = (PR_{DA} + 0.5*VOLL)q = (0.5*0 + 0.5*PR_{Lo} + 0.5*VOLL)q.$$

This is the same dispatch result and the same as the average payment in the real-time without the day-ahead market. Hence, on average there is no double payment. This condition is an inherent characteristic of the equilibrium.

Hence, within the equilibrium framework, any apparent double payments are not a problem. They average out across the different real-time conditions. The equilibrium principles follow from maintaining the right incentives, with the marginal generator in the dispatch always indifferent between providing energy or reserves, or between sales in real-time or day-ahead.

The extreme examples of the very nonlinear energy offer curve topping out at $VOLL$ would be rare in practice. The actual real-time load and the day-ahead energy dispatch should be closer. The actual virtual bids would not individually be so perfect as to be at the expected price. If there are no virtual offers and bids, generators will have an incentive to adjust day-ahead offers to reflect the same information. For example, in equilibrium a generator could set its offer to the maximum of its variable cost or the expected variable cost. But on average across all the virtual bids the market design assumption is that the day-ahead price will be a reasonable estimate of the expected real-time price (i.e., there should be price convergence between real-time and day-ahead).

Two Settlement Summary

The ORDC does require an estimate of the appropriate “discount” relative to the *VOLL*, to reflect the estimate of the marginal energy offer in the relevant dispatch. This produces different energy and scarcity prices depending on the possible outcomes in the real-time market. The day-ahead and real-time clearing energy prices never exceed the *VOLL*. The day-ahead market equilibrium condition would be at the expected value of the real-time prices, with virtual bids and offers cleared to balance the market. The prices in day-ahead and real-time are designed to be in equilibrium where the marginal generator in the dispatch is indifferent between providing energy or reserves. The day-ahead settlement is at the day-ahead prices. In the gross pool interpretation, all the day-ahead cleared transactions are financial and settle in real-time at the real-time prices. The day-ahead prices do not play a role in the real-time settlements. In any particular case, the real-time settlement payments may be greater or less than the day-ahead price. But on average, the net of day-ahead and real time settlements for all financial transactions nets out to zero. The net of all payments day-ahead and real-time for both real-time physical transactions and day-ahead financial transactions would, on average, be the same as for the physical market alone.

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¹ 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).

Attachment C
Exhibit 2

Hogan CV
March 29, 2019

WILLIAM W. HOGAN

PERSONAL DATA

Born: 1944, Holyoke, Massachusetts
 Address: Harvard Kennedy School
 Harvard University
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 Cambridge, MA 02138
william_hogan@harvard.edu
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EDUCATION

BS United States Air Force Academy, 1966
 MBA University of California, Los Angeles, 1967
 PhD University of California, Los Angeles, 1971

PROFESSIONAL EXPERIENCE

2006 - Raymond Plank Professor of Global Energy Policy, Harvard Kennedy School, Harvard University, Cambridge, Massachusetts
 2011- FTI Consulting, Boston, Massachusetts
 1999 - 2011 Director, LECCG, LLC, Cambridge, Massachusetts
 1998 - 2006 Lucius N. Littauer Professor of Public Policy and Administration, John F. Kennedy School of Government, Harvard University, Cambridge, Massachusetts
 1989 - 1999 Senior Advisor, Putnam, Hayes and Bartlett, Inc., Cambridge, Massachusetts
 1987 - 1998 Thornton Bradshaw Professor of Public Policy and Management, John F. Kennedy School of Government, Harvard University, Cambridge, Massachusetts
 1982 - 1990 Chairman, Public Policy Program, John F. Kennedy School of Government, Harvard University, Cambridge, Massachusetts
 1980 - 1997 Director, Putnam, Hayes and Bartlett, Inc., Cambridge, Massachusetts
 1978 - 1987 Professor of Political Economy, John F. Kennedy School of Government, Harvard University, Cambridge, Massachusetts
 1978 - 1986 Director, Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University, Cambridge, Massachusetts
 1976 - 1978 Adjunct Professor of Research and Scholarship, Department of Engineering-Economic Systems and Department of Operations Research, Stanford University, Stanford, California; Executive Director, Energy Modeling Forum
 1975 - 1976 Deputy Assistant Administrator for Data and Analysis, Federal Energy Administration
 1974 - 1975 Director, Office of Quantitative Methods, Federal Energy Administration
 1973 - 1974 Acting Director, Modeling Division, Office of Energy Data and Analysis, Dept. of Interior
 1971 - 1973 Instructor, U.S. Air Force Academy, Department of Economics and Management
 1969 - 1971 PhD, Department of Quantitative Methods, Graduate School of Management, Univ. of California, Los Angeles; Chairman: Dr. Arthur Geoffrion; Dissertation: "Optimization and Convergence of Extremal Value Functions Arising from Structured Nonlinear Programs"
 1968-1969; 1975 Instructor, Associate Professor (part-time), George Washington University
 1967-1969 Operations Research Analyst, U.S. Air Force, Pentagon

HONORS

Adelman-Frankel Award, United States Association for Energy Economics, October 2011

Norges Handelshoyskole (Norwegian School of Economics), Doctor *Honoris Causa*, 2011

International Association for Energy Economics (IAEE), Award for Outstanding Contributions to the Profession, 2005

Contributor, 50th Anniversary Issue, Operations Research (50:1, January-February 2002)

President's Award, Institute for Operations Research and Management Sciences (INFORMS) for long-term research with significant impact and influence on society and public policy (2000)

Distinguished Service Award (2000), Center for Business and Government, John F. Kennedy School of Government, Harvard University

Best Paper Award (1997) The Energy Journal: "A Market Power Model with Strategic Interaction in Electricity Networks."

Distinguished Service Award for Service to the Electric Utility Industry (1995), Public Utility Research Center, University of Florida

Distinguished Service Award (1975), Special Award for Exceptional Service (1976), Federal Energy Administration

Alumni Award, Outstanding Doctoral Student, University of California, Los Angeles (1971)

Outstanding Cadet Award, Engineering Management, U.S. Air Force Academy (1966)

ACTIVITIES AND ORGANIZATIONS

Visiting Committee, Institute for Data, Systems, and Society, MIT, 2018-

Future of Energy, Harvard University: Energy and Environmental Policy, Co-Chair, 2008-

Management Science and Engineering Department, Stanford University: Visiting Committee 2002-2003

Journal of Regulatory Economics: Editorial Board, 2002-

Royal Society for the Encouragement of Arts, Manufactures & Commerce, London: Fellow, 2000-2004

National Regulatory Research Institute, Ohio State University, External Review Team, 1997-2001

Energy Economics: Editorial Board, 1996-

Electricity Journal: Editorial Advisory Board, 1994-

Resource and Energy Economics: Editorial Board, 1993-1998

H. John Heinz School of Public Policy and Management, Carnegie Mellon University: Advisory Board, 1992-

2000

Electric Power Research Institute: Advisory Group for Economics, 1992-1993

Committee for Economic Development: Advisor, Design Committee on Energy and the Environment, 1990-1993

Project on Economic Reform in Ukraine: Director, 1990-1997

MIT Center for Technology, Policy and Industrial Development: Advisory Board, 1987-1996

National Research Council, Commission on Engineering and Technical Systems: Energy Engineering Board, 1986-1989

The Sawhill Commission (New York State) for the Investigation of the Public Power Option for the Long Island Lighting Company, 1986

Center for Acid Rain and Clean Air Policy Analysis, National Governors' Association: Board of Directors, 1985

International Association for Energy Economics: President, 1985

National Petroleum Council: Committee on U.S. Petroleum Refining, 1984-86

Harvard Real Estate and Planning Board: Faculty Advisory Council, 1984-

Gas Research Institute: Advisory Council, 1983-2000; Board of Directors, 1991-2000

Aspen Institute for Humanistic Studies: Energy Steering Committee, 1983-

Harvard Real Estate Corporation: Director, 1982-1983

The Energy Journal: Editorial Board, 1981-

Public Policy and Public Management Case Project: Editorial Board, 1979-1987

Operations Research: Editor, Energy and Environment, 1978-1982

Resources and Energy: Advisory Editor, 1979

National Center for Energy Systems Analysis: Advisory Board, 1979-1981

Argonne National Laboratories: Advisory Board, Energy and Environment Systems Division, 1979-1981

Undergraduate Mathematics Applications Project: Steering Committee, 1979-1981

Energy Modeling Forum, Chairman, Steering Committee, 1978-1987

Texas National Energy Modeling Project: National Advisory Board, 1978-1980

University of Texas, Center for Energy Studies: Advisory Panel, 1977-1979

International Association for Energy Economics (IAEE), 1978-

ORSA: Special Interest Group on Energy Application, Chairman, 1977-1978

Electric Power Research Institute: Supply and Demand Advisory Task Force, 1974-1976

The Mathematical Programming Society, 1971-

The Institute of Operations Research and Management Sciences (INFORMS), 1967-

STUDY GROUPS

Beyond LCOE External Advisory Board, Department of Energy, 2019-

Task Force to Support the Quadrennial Energy Review, Secretary of Energy Advisory Board, 2014-2016

Committee on Accelerating Deployment of Clean Energy and Energy Efficiency Technologies, National Academy of Sciences Energy Study, 2013-2016

MIT Grid Study, 2009-2011

Harnessing Renewable Energy, 2009-2010

Populism and Natural Resources: An Energy Policy Agenda, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, Harvard University, 2006-2009

Repsol YPF-Harvard Kennedy School Fellows Program, Director, 2002-2006

Initiative on the Future of Electricity, Edison Electric Institute, 1999

Independent Expert Review Panel, U. S. Energy Information Administration Review of the Economic Effects of the Kyoto Protocol, 1998

Electric Utility Market Reform Task Force, Massachusetts Dept of Energy and Resources, 1994-1995

Harvard Electricity Policy Group, Research Director, 1993-

Repsol YPF - Harvard Seminars in Energy Policy, Co-Chair, 1988-

Energy Modeling Forum Working Groups: Energy and the Economy (Chairman), 1976-1977; Coal in Transition, 1977-1978; Electric Load Forecasting, 1977-1979; Demand Elasticities (Chairman), 1978-1980; Oil and Gas Supply, 1979-1982; World Oil Models, 1980-1982; Energy Shocks, 1982-1984; Industrial Energy Demand, Conservation and Interfuel Substitution, 1984-1986; International Oil Supplies and Demands, 1989-1991.

Energy Efficiency: A New Agenda, Task Group, American Council for an Energy Efficient Economy, 1988

Diesel Impacts Study Committee, National Research Council, 1979-1981

Resources for the Future: Energy, the Next Twenty Years, sponsored by the Ford Foundation, 1978-1979

Modeling Resources Group, Committee on Nuclear and Alternative Energy Systems, National Academy of Sciences, 1976-1977.

BOOKS AND ARTICLES

“A Primer on Transmission Benefits and Cost Allocation.” *Economics of Energy & Environmental Policy*, March 2018.

“Best Electricity Market Design Practices: In My View.” *IEEE Power and Energy*, January 2018.

“Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT” (with Susan Pope), May 9, 2017.

The Power of Change: Innovation for Development and Deployment of Increasingly Clean Electric Power Technologies (committee member, National Academies of Science, Engineering, and Medicine book), September 2016.

“Virtual Bidding and Electricity Market Design.” *The Electricity Journal*, June 2016.

“Co-Optimization of Power and Reserves in Dynamic T&D Power Markets with Nondispatchable Renewable Generation and Distributed Energy Resources” (co-author with Michael Caramanis, Elli Ntakou, Aranya Chakraborty and Jens Schoene), *Proceedings of the IEEE*, April 2016.

“Electricity Markets and the Clean Power Plan,” *The Electricity Journal*, November 2015.

“A Cleaner Energy System: Renewable Energy and Electricity Market Design [In My View],” *IEEE Power & Energy Magazine*, July 2015.

“Electricity Market Design and Efficient Pricing: Applications for New England and Beyond,” *The Electricity Journal*, August-September 2014.

“Electricity Scarcity Pricing Through Operating Reserves,” *Economics of Energy & Environmental Policy*, Vol. 2, Issue 2, September 2013.

“Financial Transmission Rights: Point-to-Point Formulations,” chapter in Rosellón, Juan and Tarjei Kristiansen, ed., *Financial Transmission Rights: Analysis, Experiences and Prospects*. London: Springer, 2013.

“Multiple Market-Clearing Prices, Electricity Market Design and Price Manipulation,” *The Electricity Journal*, Vol. 25 Issue 4, May 2012.

“Towards a Combined Merchant-Regulatory Mechanism for Electricity Transmission Expansion,” with Juan Rosellón and Ingo Vogelsang, *Journal of Regulatory Economics*, Vol. 38, No. 2, October 2010.

“Electricity Wholesale Market Design in a Low-Carbon Future,” chapter in Mosele, Boaz, Jorge Padilla and Richard Schmalensee, *Harnessing Renewable Energy in Electric Power Systems: Theory, Practice, Policy*. Washington, DC: RFF Press, 2010.

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"Transmission Market Design," in Electricity Deregulation: Where To From Here?, James Griffin, editor, University of Chicago Press, 2005.

"Resource Adequacy and Electricity Markets," EnergyBiz, September-October, 2005.

"Shedding Light," Op-Ed in The Wall Street Journal, April 19, 2004.

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"Energy Modeling for Policy Studies," Operations Research, Fiftieth Anniversary Issue, January- February 2002.

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"The Slippery Slope of Socialization," Public Utilities Fortnightly , December 1, 2001

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"Regional Transmission Organizations: Market Institutions for Electric Network Systems," The Utilities Project: the Impact of Competition, Montgomery Research/ PriceWaterhouseCoopers, San Francisco, 2000.

"The Power of Competition," RSA Journal, Royal Society for the Encouragement of Arts, Manufactures & Commerce, London, UK, February 2000.

"A Concurrent Auction Model for Transmission Congestion Contracts," Energy and Environmental Policy Modeling, John Weyant, editor, Kluwer Academic Publishers, 1999.

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"Nodes and Zones in Electricity Markets: Seeking Simplified Congestion Pricing," Designing Competitive Electricity Markets, Hung-po Chao and Hillard Huntington, editors, Kluwer Academic Publishers, 1998.

"WEPEX: What's Wrong With Least Cost?" Public Utilities Fortnightly, January 1, 1998.

"A Market Power Model with Strategic Interaction in Electricity Networks," The Energy Journal, Vol. 18, No. 4, 1997.

Transmission Rights, Through the Looking Glass: A False Dichotomy Between Active and Passive Trading," The Electricity Journal, Vol. 10, No. 8, October 1997.

"Market Power and Strategic Interaction in Electricity Networks," (with Judith Cardell and Carrie Cullen Hitt), Resource and Energy Economics, Vol. 19, 1997.

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"An Efficient Concurrent Auction Model for Firm Natural Gas Transportation Capacity," Information Systems and Operational Research, Vol 30, No. 3, August 1992.

"Energy and Information Network Infrastructures." Building Information Infrastructure, Brian Kahin editor, McGraw Hill, 1992.

"Economic Reforms in the Sovereign States of the Former Soviet Union," Brookings Papers on Economic Activity, William G. Brainard and George L. Perry, editors, Washington, D.C., Vol. 2, 1991.

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"A Dynamic Putty - Semi-Putty Model of Aggregate Energy Demand," Energy Economics, Vol. 11, No. 1, January 1989.

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Lower Oil Prices: Mapping the Impact (with Bijan Mossavar-Rahmani et al.), Harvard University Energy and Environmental Policy Center, 1988.

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"Energy Security and Oil Market Risk Analysis" (with Paul N. Leiby.) In Energy Decisions for the Future: Proceedings of the Eighth Annual International Conference of the IAEE, Mitsuru Miyata and Kenichi Matsui, editors, Tokyo, 1986.

"Patterns of Energy Use." In Energy Conservation: Successes and Failures, John C. Sawhill and Richard Cotton, editors, The Brookings Institute, 1986.

"Energy and Economy: Global Interdependences," Energy Journal, Vol. 6, No. 4, 1985.

"Integrated Fuel and Investment Planning: Methods and Process" (with Charles Mann, Susan Manning, and Darrell Smith.) In Models in the Decision Making Process: Planning Under Uncertainty, Andrew Kydes, editor, North-Holland, 1985.

"Energy, the Economy, and Oil Security." In Improving U.S. Energy Security, Richard Gonzales, et al, editors, Ballinger Publishing Co., 1985.

"Energy Policy." In Energy Resources and National Policy: The Reagan Approach, Paul R. Portney, editor, Urban Institute Press, 1984.

"Oil Stockpiling: Help Thy Neighbor," Energy Journal, Vol. 4, No. 3, 1983.

"Methods and Algorithms for Combining Energy Models: Optimization in a Network of Process Models", (with John Weyant). In Energy Models and Studies, Studies in Management Science and Systems, B. Lev, editor, Vol. 20, 1983.

Caught Unawares: the Energy Decade in Retrospect, with Martin Greenberger, et al., Ballinger Publishing Company, 1983.

"Alternatives to Transfer of Large-Scale Models." In Large Scale Energy Models, Robert M. Thrall, Russell G. Thompson, and Milton L. Holloway, editors, Westview Press, 1983.

"Policies for Oil Importers." In OPEC Behavior and World Oil Prices, J. Griffin and D. Teece, editors, George Allen and Unwin, London, 1982.

"On Convergence of the PIES Algorithm for Computing Equilibria," with B. H. Ahn, Operations Research, Vol. 30, No. 2, 1982.

Decision Analysis of Regulating Diesel Cars, National Academy Press, 1982.

"Combined Energy Models." In Advances in the Economics of Energy and Resources, Vol. 4, John. R. Moroney, editor, JAI Press, 1982.

"Energy and Security Policy." In Toward A New U.S. Industrial Policy?, Michael L. Wachter and Susan M. Wachter, editors, University of Pennsylvania Press, 1981.

"Import Management and Oil Emergencies." In Energy and Security, David Deese and Joseph Nye, editors, Ballinger Publishing Co., 1981.

"Aggregate Elasticity of Energy Demand," with the EMF Working Group, The Energy Journal, Vol. 2, No. 2, 1981.

"Gasoline, Prices, Taxes and Demand." In The Dependence Dilemma: U.S. Gasoline Consumption and America's Security, Daniel Yergin, editor, Center for International Affairs, Harvard University, 1980.

"Economic Growth and Higher-Priced Energy." In Energy in America: Fifteen Views, S. Ramo, editor, Center for the Study of the American Experience, University of Southern California, 1980.

"Alternatives to Transfer of Large-Scale Models," Simulation, April 1980.

Background Papers for Energy: The Next Twenty Years, contributor, H. Landsberg, editor, Ballinger Press, 1980.

"Capital Energy Complementarity in Aggregate Energy-Economic Analysis," Resources and Energy, Vol. 2, North-Holland Publishing Company, 1979.

Energy: The Next Twenty Years, contributor. A Ford Foundation/Resources for the Future Report, Ballinger Press, 1979.

Energy Information: Description, Diagnosis, and Design, editor and contributor. Stanford Institute for Energy Studies, Stanford University, 1979.

"Energy and Economic Growth." In Energy Conservation and Public Policy, John Sawhill, editor, Prentice-Hall, 1979.

"The Energy Modeling Forum: A Communication Bridge," in K.B. Haley, Operational Research, '78, North-Holland Publishing Company, 1979.

"Policy Modeling for Energy Decision," The Stanford Engineer, Stanford University, Winter 1978.

"Energy Modeling: Building Understanding for Better Use," Proceedings, Second Lawrence Symposium on Systems and Decision Sciences, 1978.

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"Optimizing the Procurement of Aviation Fuels," with Larry Austin, Management Science, Vol. 22, No. 5, 1976.

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"Toward the Development of an Equilibrium Capital Market Model Based on Semivariance," (with J.S. Warren), Journal of Financial and Quantitative Analysis, Vol. 9, January 1974.

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SELECTED RECENT WORKING PAPERS AND OTHER DOCUMENTS

Selected recent works among many available on Professor Hogan's website:

<http://www.whogan.com>

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Multiple Market-Clearing Prices, Electricity Market Design and Price Manipulation. March 31, 2012.

The Future of the Electric Grid: An Interdisciplinary MIT Study, December 2011. Study Participant.

Electricity Market Reform: Market Design and Extended LMP. NHH Workshop on Pricing in Deregulated Energy Markets presentation, Voss, Norway. November 28, 2011.

Energy Security and Energy Policy, Energy: Transition to a Sustainable Future presentation, part of the 2011 Industrial Physics Forum, Nashville, TN, October 31, 2011.

Allocating Costs Commensurate with Transmission Benefits, Northeast Energy and Commercial

Association presentation, Boston. October 13, 2011.

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Attachment B: "Comments on the Congestion Management Proposal of the California ISO," (with Scott M. Harvey.)

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1986.

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SPEECHES, CONFERENCES AND OTHER ACTIVITIES

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Half Moon Bay, CA, March 2019.

Speaker, Yes Energy User Group Summit, Boulder, CO, February 2019.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Palm Beach, FL, December 2018.

Keynote, Platts 11th Annual Nodal Trader Conference, New York, NY, October 2018.

Panelist, World Bank, Washington, DC, September 2018.

Panelist, IAEE conference, Groningen, Netherlands, June 2018.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, June 2018.

Panelist, Energy Bar Association, Washington, DC, June 2018.

Panelist, Skadden Energy Conference, Washington, DC, April 2018.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Washington, DC, March 2018.

Speaker, Yes Energy User Group Summit, Boulder, CO, March 2018.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Palm Beach, FL, January 2018.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Calgary, AB, October 2017.

Keynote, Gas and Power Institute, Houston, TX, September 2017.

Panelist, The Future of Power Markets in a Low Marginal Cost World, Washington, DC, August 2017.

Speaker, Public Utility Commission of Texas, Austin, TX, August 2017.

Keynote, Chile Energy Day, Washington, DC, June 2017.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, June 2017.

Panelist, Edison Electric Institute convention, Boston, MA, June 2017.

Panelist, Federalist Society “State ‘Around Market’ Action and FERC: The End of Competitive Wholesale Electric Markets?” conference, Washington, DC, April 2017.

Keynote speaker, EUCI “Price Formation Issues in Wholesale Energy Markets” conference, Baltimore, MD, April 2017.

Panelist, Skadden Energy Conference, Washington, DC, March 2017.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Savannah, GA, March 2017.

Speaker, Enel Group Foundation Talks, Rome, January 2017.

Panelist, Hawaii International System Science Conference, Waikoloa, HI, January 2017.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Scottsdale, AZ, December 2016.

Panelist, National Conference of State Legislatures Capitol Forum, December 2016.

Moderator, New England Legal Foundation CEO Forum, Boston, MA, December 2016.

Distinguished Speaker Series, MIT Energy Initiative, November 2016.

Moderator, Platts Annual Nodal Trader Conference, New York, NY, October 2016.

Panelist, Organization of PJM States annual meeting, October 2016.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Washington, DC, October 2016.

Panelist, Institute for Data, Systems, and Society, MIT, September 2016.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, June 2016.

Panelist, "Designing Markets for a Decarbonizing Power System," MIT Energy Institute, Cambridge, MA, May 2016.

Panelist, Electric Power Supply Association annual meeting, Chicago, IL, April 2016.

Keynote Speaker, National Capitol Area Chapter, United States Association for Energy Economics, April 2016.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Washington, DC, March 2016.

Speaker, FERC Legacy Series, Washington, DC, February 2016.

Panelist, Energy Mexico 2016, Mexico City, January 2016.

Speaker, UCLA IPAM workshop, Los Angeles, CA, January 2016.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Palm Beach, FL, December 2015.

Keynote speaker, MIT Center for Energy and Environmental Policy Research workshop, Cambridge, MA, November 2015.

Panelist, New England Energy Policy Summit, Cambridge, MA, October 2015.

Panelist, EUCI conference, Cambridge, MA, September 2015.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Washington, DC, June 2015.

Panelist, Skadden Energy Roundtable, Washington, DC, June 2015.

Speaker, Energy Bar Association, Newark, NJ, June 2015.

Keynote speaker, Associated Electric Cooperative annual meeting, Branson, MO, June 2015.

Panelist, A Symposium on Market Power and Market Manipulation in Energy Markets, Washington, DC, May 2015.

Speaker, Workshop on the Analysis and Management of Energy and Environmental Policy, Cambridge, MA, April 2015.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Half Moon Bay, CA, March 2015.

Speaker, Symposium on Mexico's Energy Reforms, Tufts University, Medford, MA, February 2015.

Speaker, Harvard National Model United Nations, Boston, MA, February 2015.

Speaker, EU Electricity Markets for Renewable Integration workshop, DIW Berlin, January 2015.

Panelist, Energy Bar Association meeting, Washington, DC, January 2015.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, New Orleans, LA, December 2014.

Keynote speaker, Platts Nodal Trader Conference, New York, NY, October 2014.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, October 2014.

Speaker, USAEE Breakfast Energy Series of Talks, Washington, DC, July 2014.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, June 2014.

Panelist, NYISO 2014 Energy Conference, New York, NY, June 2014.

Panelist, Restructuring the Electricity Sector in Japan, Brookings Institution, March 2014.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Santa Monica, CA, February 2014.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Tucson, AZ, December 2013.

Panelist, NARUC annual conference, Orlando, FL, October 2013.

Panelist, EUCI Scarcity Pricing Conference, Baltimore, MD, November 2013.

Panelist, NECA, Power Markets Conference, Westborough, MA, October 2013.

Keynote speaker, Platts Nodal Trader Conference, New York, NY, October 2013.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, September 2013.

Keynote speaker, Nexant User Conference, San Diego, CA, September 2013.

Panelist, Aspen Energy Forum, Aspen, CO, July 2013.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Calgary, AB, June 2013.

Speaker, Electricity Market Design on Two Sides of the Atlantic, CEEPR, MIT, May 2013.

Panelist, Austin Electricity Conference, April 2013.

Panelist, Gulf Coast Power Association, Houston, TX, April 2013.

Speaker, Skadden Enforcement and Compliance Conference, Washington, DC, March 2013.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Dana Point, CA, March 2013.

Speaker, 40th Annual Public Utilities Research Center conference, University of Florida, Gainesville, February 2013.

Keynote speaker, The Economics of Energy Markets Conference, Toulouse, France, January 2013.

Speaker, International Experience in Transmission Planning and Delivery conference, Imperial College, London, UK, January 2013.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Washington, DC, December 2012.

Speaker, International Association of Energy Economics conference, Austin, TX, November 2012.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, October 2012.

Speaker, Energy Compliance Network, Houston, TX, October 2012.

Speaker, Australian Competition and Consumer Commission regulatory conference, Brisbane, July 2012.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, June 2012.

Speaker, Geopolitics of Natural Gas Workshop, Baker Institute, Rice University, Houston, TX, May 2012.

Speaker, Weston Roundtable Series, University of Wisconsin, Madison, WI, April 2012.

Speaker, Pressing Issues in World Energy Policy, University of Florida, Gainesville, FL, March 2012.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Santa Monica, CA, February 2012.

Speaker, Projects & Money 2012 conference, New Orleans, LA, January 2012.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Dallas, TX, December 2011.

Speaker, NHH Workshop on Pricing in Deregulated Energy Markets, Voss, Norway, November 2011.

Panelist, BP/Harvard Kennedy School Symposium on Energy, Climate and Security Policy. Cambridge, MA, November 2011.

Speaker, Energy: Transition to a Sustainable Future, part of 2011 Industrial Physics Forum, Nashville, TN, October 2011.

Keynote speaker, Independent Oil Marketers Association of New England, Westborough, MA, October 2011.

Conference Co-Chair and panelist, Harvard Electricity Policy Group Plenary Session, Nashville, TN, September 2011.

Panelist, Aspen Energy Policy Forum, Aspen, CO, July 2011.

Panelist, "Institutions, Efficiency and Evolving Energy Technologies," International Association for Energy Economics, June 2011.

Keynote speaker, The Economics of Energy Markets Conference, Toulouse, France, June 2011.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Washington, DC, May 2011.

Panelist, "EPRG Spring Research Seminar: Renewable Energy Policy," Robinson College, University of Cambridge, UK.

Panelist, "Overcoming Barriers to Smart Grids & New Energy Services," University of Texas, Austin, TX.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Rancho Palos Verdes, CA, February 2011.

Moderator, "New Realities: Russia's Natural Gas Sector in Light of Shale Gas and LNG Advances," Russian Energy Conference, Harvard University, December 2010.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Tucson, AZ, December 2010.

Panelist, "Are the Wholesale Power Markets Delivering Benefits – An Open Forum Discussion," Northeast Energy and Commerce Association "Looming Changes in ISO New England's Power Markets" conference, November 2010.

Keynote Speaker, Boston Cleantech Venture Day, "Electricity Market Reform: Market Design, Smart Pricing and the Green Agenda," Boston, MA, November 2010.

Panel moderator, Chasing the Balance: Our Energy Future, Harvard Business School, October 2010.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, October 2010.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Santa Monica, CA, May 2010.

Panelist, "Fair Pricing: A Conference on Ethics and Dynamic Pricing," Rutgers Business School, Newark, NJ, April 9, 2010.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Santa Monica, CA, February 2010.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Austin, TX, December 2009.

Speaker, Singapore Electricity Roundtable, "Competitive Electricity Markets – Trends and Developments," Singapore, November 17, 2009.

Speaker, Exelon/Energy Bar Association workshop on Scarcity Pricing, Washington, DC, October 16, 2009.

Speaker, MIT Operations Research Center Seminar Series, October 15, 2009.

Keynote Speaker, National Energy Policy Institute conference on “Power for the 21st Century: Reinventing America’s Power Grid,” Tulsa, OK, October 7, 2009.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, October 2009.

Speaker, Elforsk Market Design and SAEF conference, “Design of Competitive Electricity Markets, Stockholm, Sweden, September 17-18, 2009.

Speaker, EUCI Conference on “FTRs – Where are We Now?,” Washington, D.C., July 2009.

Speaker, White House Council on Environmental Quality, Washington, D.C., July 2009.

Lecturer, Infrastructure in a Market Economy, Harvard Kennedy School, Cambridge, MA, July 2009.

Speaker, Aspen Institute: 2009 Energy Policy Forum, “The Goals: An Electricity Grid for 21st Century,” July 2009.

Conference Co-Chair, Harvard Electricity Policy Group 55th Plenary Session, Cambridge, MA, May 2009.

Panelist, “Scarcity Pricing and Solutions,” Exelon Power Team, Kennett Square, PA, May 2009.

Panelist, “Disrupting the Status Quo in Electric Energy Management,” Boston University, Brookline, MA, May 2009.

Presenter, “Smart Grid Regulation,” GE Energy, Atlanta, GA, May 2009.

Keynote speaker, “Stimulating Energy Symposium”, Harvard University, Cambridge, MA, May 2009.

Panelist, “Regulation and Electricity Markets,” Western Power Trading Forum, New York, NY, April 2009.

Press release of study: Alternative Power Market Proposals Reflect Fundamental Misunderstandings of RTO Markets, FERC, Washington, DC, April 2009.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, La Jolla, CA, March 2009.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Atlanta, GA, December, 2008.

Panelist, “Energy Policy and Energy Interdependence,” Hudson Institute, Washington, DC, Nov. 18, 2008.

Moderator, “Challenges in Energy Law and Litigation,” LECG XPRT Forum, Santa Barbara, CA, November 14, 2008.

Participant, “Dubai, Summit on the Global Agenda,” Dubai, United Arab Emirates, November 7-9, 2008.

Panelist, “NECA 2008 Power Markets Conference, Westboro, MA, October 30, 2008.

Panelist, “Energy Policy Challenges: Is the Past Prologue?,” Resources for the Future, Washington, DC, October 29, 2008.

Participant, Harvard University Sustainability Celebration with Harvard President Drew Faust and Al Gore, Cambridge, MA, October 22, 2008.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Chicago, IL, October, 2008.

Panelist, "Powering the Future: Key Energy Issues for the Next Administration," Technology Policy Institute, Washington, D.C., September 26, 2008.

Steering Committee Co-Chair and Panelist, Harvard Kennedy School workshop, "Acting in Time on Energy Policy," Cambridge, MA, September 18-19, 2008.

Speaker, NYISO Annual Board Retreat, Rye, NY, September 14, 2008.

Keynote Presenter, PSEG Executive Session, "Electricity Market Design: Regulation and Market Reforms," Newark, NJ, August 11, 2008.

Speaker, Aspen Institute: 2008 Energy Policy Forum, "Climate Change and the Electricity Sector," July 2008.

Panelist, "Advancing Sustainability in the Oil and Gas Industry," World Petroleum Congress, Madrid, Spain, July 2, 2008.

Keynote Presenter, IDEI Conference: The Economics of Energy Markets, "Market-Clearing Electricity Prices and Energy Uplift," Toulouse, France, June 20, 2008.

Presenter, "Acting in Time: Regulating Wholesale Electricity Markets," Federal Energy Regulatory Commission Conference on Competition in Wholesale Power Markets, May 8, 2007.

Speaker, "Electricity Market Design: Coordination, Pricing and Incentives," ERCOT Energized Conference, Austin, TX, May 2008.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, May 2008.

Panelist, "Challenges for Long-Term Energy Models," Energy Information Administration Conference, Washington, DC, April 6-8, 2008.

Keynote Speaker, 15th Annual U.S.-Japan Symposium, "Stability and Sustainable Growth in the Asia/Pacific Region," Harvard Kennedy School, Cambridge, MA, March 18, 2008.

Panelist, "Reliability and Competition: The Price of Reliability?," Independent Power Producers of Alberta 2008 Annual Conference, Banff, Alberta, Canada, March 10, 2008.

"Electricity Market Design: Coordination, Pricing and Incentives," Faculty Research Seminar, Harvard Kennedy School, Cambridge, MA, March 5, 2008.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Boulder, CO, February 28-29, 2008.

"Electricity Market Design: Coordination, Pricing and Incentives," Energy Policy Research Seminar, Harvard Kennedy School, Cambridge, MA, February 12, 2008.

Keynote Presenter, La Asociación Española para la Economía Energética (AEEE), Bilbao, Spain, January 2008.

Conference Co-Chair, Harvard Electricity Policy Group Plenary Session, Los Angeles, CA, December 2007.

Co-Chair, Kennedy School of Government, Harvard University, "Populism and Natural Resources" workshop, Cambridge, MA, November 2007.

Panelist, Harvard University, "Climate Engineering" workshop, Cambridge, MA, November 2007.

Speaker, Kennedy School of Government Alumni Refresher, Harvard University, "Electricity Market Design(s): Public Purposes and Policy Analysis," Cambridge, MA, November 2007.

Speaker, Club de Madrid "Energy and Democracy" conference, "Democratizing Energy," Madrid, Spain, November 2007.

Speaker, 27th USAEE/IAEE North American Conference, "Electricity Hybrids: Mixed Market Designs and Infrastructure Investments," Houston, TX, September 2007.

Speaker, Edison Electric Institute, 2007 Transmission and Wholesale Markets School, Madison, WI, July 2007.

Speaker, Real Colegio Complutense en Harvard, "Energy Industry Restructuring," Cambridge, MA, July 2007.

Speaker, 2007 Aspen Energy Policy Forum, "Electricity Markets – Where Are We Going?" July 2007.

Conference Co-Chair, Harvard Electricity Policy Group 47th Plenary Session, Cambridge, MA, June 2007.

Speaker, 14th Annual New England Energy Conference and Exposition, "Moving Into a Secure and Competitive Future," Mystic, CT, May 2007.

Discussant, 15th Economia Panel Meeting, Yale University, New Haven, CT, May 2007.

Conference Co-Chair, Harvard Electricity Policy Group 46th Plenary Session, Laguna Beach, CA, March 2007.

Speaker, Institut D'Economie Industrielle, Toulouse, Conference on the Economics of Energy Markets, Toulouse, France, January 2007.

Conference Co-Chair, Harvard Electricity Policy Group 45th Plenary Session, Dallas, TX, December 2006.

Speaker, University of Massachusetts INFORMS Seminar, Electricity Market Restructuring and Operations Research, Amherst, MA, October 2006.

Speaker, EUCI Conference on Transmission Reliability, Washington D.C., October 2006.

Conference Co-Chair, Harvard Electricity Policy Group 44th Plenary Session, Cambridge, MA, September 2006.

Conference Co-Chair, XVI Repsol YPF – Harvard Seminar on Energy Policy, Energy Markets, Security, Transparency, Barcelona, Spain, September 2006.

Keynote Speaker, 26th USAEE/ IAEE Annual North American Conference, Ann Arbor, MI, September 2006

Speaker: Edison Electric Institute, Transmission Market and Design Course, University of Wisconsin-Madison, Madison, WI, July 2006.

Keynote Speaker, Independent Power Producers Society of Alberta, Canada (IPPSA), Roundtable re Electricity Restructuring, Long-term Adequacy, Market Design, Calgary, Canada, June 2006.

Conference Co-Chair, Harvard Electricity Policy Group 43rd Plenary Session, Cambridge, MA, June 2006.

Speaker, Real Colegio Complutense - Harvard, Seminar on Government Restructuring: Privatization, Regulation and Competition, Cambridge MA, June 2006.

Speaker, Plenary Session, New England Conference of Public Utility Commissioners (NECPUC), Rockport, ME, June 2006.

Keynote Speaker, Infocast Conference on Open Access Transmission Tariff (OATT) Reform, Washington, D.C., June 2006.

Commentator, Conference on Venezuelan Economic Growth 1970-2005, Center for International Development, Harvard University, Cambridge MA, April 2006.

Speaker, University of California Energy Institute, POWER Conference, Berkeley, CA, March 2006.

Conference Co-Chair, Harvard Electricity Policy Group 42nd Plenary Session, La Jolla, CA, March 2006.

Speaker, Florence School of Regulation, Workshop on the Role and Status of Power Exchanges, European University Institute, Florence, Italy, January 2006.

Speaker, New York Independent System Operator, Workshop on Transmission Investments in Deregulated Markets, Albany, NY, December 2005.

Conference Co-Chair, Harvard Electricity Policy Group 41st Plenary Session, Atlanta, GA, December 2005.

Speaker, The Association of Power Exchanges [APEX] 2005 Annual Conference, Orlando, FL, November 2005.

Speaker, EUCI Conference on "Open Access: Are We There Yet?" Washington, D.C., October 2005.

Speaker, EUCI Conference on Transmission Investments and Reliability, Brewster, MA, September 2005.

Conference Co-Chair, Harvard Electricity Policy Group 40th Plenary Session, Cambridge, MA, September 2005.

Speaker, IAEE European Energy Conference, European Energy Markets in Transition, Bergen, Norway, August 2005.

Speaker, NARUC Electricity Committee Summer Conference, Austin, TX, July 2005.

Conference Co-Chair, Speaker, XV Repsol YPF - Harvard Seminar on Energy Policy, Making Energy Policy Work, Lisbon, Portugal, June 2005.

Speaker, IDEI Conference on the Economics of Electricity Markets, Toulouse, France, June 2005.

Conference Co-Chair, Harvard Electricity Policy Group 39th Plenary Session, Cambridge, MA, May 2005.

Speaker, McDermott, Will & Emery Energy Conference, Washington, D.C., April 2005.

Conference Co-Chair, Harvard Electricity Policy Group 38th Plenary Session, San Diego, CA, March 2005.

Speaker, American Antitrust Institute, Conference on Open Access Revisited: Lessons Learned, Arlington, VA, January 2005.

Speaker, Carnegie-Mellon University, Workshop on Electricity Transmission in Deregulated Markets, Pittsburgh, PA, December 2004.

Conference Co-Chair and Speaker, Harvard Electricity Policy Group Plenary Session, Austin TX, December 2004.

Conference Co-Chair, Harvard Electricity Policy Group 37th Plenary Session, Austin, TX, December 2004.

Speaker, IEEE/PSCE Power Systems Conference & Exposition, New York, NY, October 2004.

Conference Co-Chair, Harvard Electricity Policy Group 36th Plenary Session, Cambridge, MA, October 2004.

Speaker, IAAE European Conference on Modeling Energy Economics and Policy, Zurich, Switzerland, September 2004.

Speaker, EEI Market Design and Transmission Pricing School, Madison, WI, July 2004.

Conference Co-Chair, XIV Repsol YPF-Harvard Seminar on Energy Policy, Managing Energy Markets, A Coruña, Spain, June 2004.

Conference Co-Chair, Harvard Electricity Policy Group 35th Plenary Session, Cambridge, MA, May 2004.

Speaker, EUCI Conference on Preventing the Next Blackout, Washington D.C., April 2004.

Speaker, Panel Chair, U. Richmond Law School, Merhige Center of Environmental Law, Conference on The Blackout of 2003: What's Next? Richmond, VA, April 2004.

Conference Chair, Speaker, IEA Workshop on Transmission Network Reliability in Competitive Electricity Markets, Paris, France, March 2004.

Conference Co-Chair, Harvard Electricity Policy Group 34th Plenary Session, San Diego, CA, March 2004.

Speaker: CIDE-CRE Seminar: Energy Regulatory Developments in North America, Mexico City, Mexico, January, 2004.

Speaker, Infocast Transmission Executive Forum: Unlocking Transmission Investment, Washington D.C., January, 2004.

Speaker, IDEI Conference on Competition and Coordination in the Electricity Industry, Toulouse, France, January 2004.

Conference Co-Chair, Harvard Electricity Policy Group 33rd Plenary Session, Point Clear, AL, December 2003.

Session Chair, Conference on Wholesale Power Markets in New England, NECA, Boston, MA, November, 2003.

Speaker, New Directions in Regulation Seminar, Kennedy School of Government, Cambridge MA, October 2003.

Conference Co-Chair, Harvard Electricity Policy Group 32nd Plenary Session, Cambridge, MA, September 2003.

Speaker, EEI Market Design and Transmission Pricing School, Madison, WI, July 2003.

Session Chair, Aspen Institute Summer Energy Forum, Aspen, CO, July 2003.

Speaker, Standard and Poors 2003 Utility and Energy Conference, New York, NY, June 2003.

Speaker, ESAI Northeast Locational Energy Roundtable, Wakefield, MA, June 2003.

Speaker, 10th Annual Spring Energy Conference, NECA, Mystic, CT, June 2003.

Keynote Speaker, VII Latin American Energy Regulatory Entities Association (ARIAE) annual meeting, Oaxaca, Mexico, May 2003.

Conference Chair, XIII Repsol YPF-Harvard Seminar on Energy Policy, Salamanca, Spain, May 2003.

Conference Co-Chair, Harvard Electricity Policy Group 31st Plenary Session, Cambridge, MA, May 2003.

Speaker: 20th Annual Platts User Conference, Amelia Island, FL, April 2003.

Speaker, Conference on Deregulation in a Turbulent World, Maguire Energy Institute, Southern Methodist University, Dallas TX, April 2003.

Speaker, Conference on Electricity Deregulation: Where to From Here? Bush Presidential Conference Center, Texas A&M University, College Station, TX, April 2003.

Conference Co-Chair, Harvard Electricity Policy Group Special Session on Transmission, Cincinnati, OH, April 2003.

Speaker, EIA 2003 National Energy Modeling System, Annual Energy Outlook Conference, Washington D.C., March 18, 2003.

Speaker, U.S. Department of State-sponsored videoconference from Australia, "Creating a Competitive Electricity and Gas Market." Cambridge, MA, USA and Canberra, Australia, February 2003.

Conference Co-Chair, Harvard Electricity Policy Group 30th Plenary Session, Palm Springs, CA, January 2003.

Speaker, Center for Energy and Environmental Policy Research, MIT, Workshop, Cambridge, MA, December 2002.

Session Co-Chair, Harvard Electricity Policy Group Special Session on Western Issues, Denver CO, December 2002.

Speaker, Nordic Energy Research Council, Conference on Electricity Market Reforms, Experiences and Lessons for the Future, Copenhagen, Denmark, November 2002.

Keynote Speaker, US Combined Heat and Power Association, 3d Annual Conference, Boston, MA, October 2002.

Panel Chair, ABA Section of Environment, Energy and Resources, Fall Meeting. Panel on FERC Rulemaking and Orders on RTO Development and Wholesale Electricity Market Structure," Portland, OR, October 2002.

Conference Co-Chair, Harvard Electricity Policy Group 29th Plenary Session, Cambridge, MA, September 2002.

Speaker, Harvard Business School Senior Executive Program/ E.ON Academy, Boston, MA, August 2002.

Speaker, Christensen Associates Conference on Connecting Wholesale and Retail Electricity Markets, Denver, CO, August 2002.

Speaker, EEI Market Design and Transmission Pricing School, Madison, WI, July 2002.

Speaker, 25th Annual IAAE International Conference, Aberdeen, Scotland, June 2002.

Conference Co-Chair, Harvard Electricity Policy Group 28th Plenary Session, Cambridge, MA, May 2002.

Speaker, Platts RDI User Conference, Amelia Island, Florida, April 2002.

Speaker, ABA Antitrust Section Spring Meeting, Washington, D.C., April 2002.

Conference Co-Chair, Harvard Electricity Policy Group Special Session, Atlanta, GA, April 2002.

Speaker, Carnegie-Mellon-Stanford Workshop on Energy Research Programs, Washington D.C. April 2002.

Keynote Speaker, USAEE /SAIS Washington Energy Policy Conference: New Developments in Electric Market Restructuring" Washington D.C., May 2002.

Speaker, Center for Research in Regulated Industries, Rutgers University, Advanced Workshop in Regulation and Competition, 21st Annual Eastern Conference, Newport, RI, May 2002.

Speaker, Harvard-Japan Project on Energy and the Environment, Tokyo Conference, Tokyo, Japan, January 2002.

Conference Co-Chair, Harvard Electricity Policy Group 27th Plenary Session, San Diego, CA, January 2002.

Keynote Speaker, ESAI Roundtable on Northeast Power Prices, Wakefield, MA, January 2002.

Keynote Speaker, Iberdrola Group Conference on Ten Years of Electricity Liberalization and Restructuring: Lessons Learned and Future Challenges, Madrid, Spain, December 2001.

Speaker, Commission de Regulation de l'Electricite, France, Conference on Market Design in Restructured Electricity Markets, Paris, France, November 2001.

Conference Co-Chair, Harvard Electricity Policy Group Special Session on Market Design, Cambridge, MA, September 2001.

Session Chair, National Association of Attorneys General, Energy Conference, Boston, MA, November 2001.

Speaker, Eighth Annual Kentucky Utility Conference, Lexington, KY, October 2001.

Conference Co-Chair, Harvard Electricity Policy Group, 26th Plenary Session, Washington, D.C., September 2001.

Speaker, Conference on Reform in the Mexican Electricity Industry, CIDE, Mexico City, September 2001.

Speaker, N.E. Environmental Protection Agency, Conference on "Keeping the Lights On and the Air Clean: Making the Energy-Environment Connection in New England," Cambridge, MA, July 2001.

Seminar Co-Chair, XII Repsol YPF - Harvard Seminar on Energy Policy, Energy Liberalization and Regulation: Revisiting Objectives and Results, Palma de Mallorca, Spain, July 2001.

Conference Co-Chair, Aspen Institute Program on Energy, the Environment, and the Economy, Forum on Energy Supplies and the Infrastructure, Aspen, CO, June 2001.

Conference Co-Chair, Harvard Electricity Policy Group 25th Plenary Session, Cambridge, MA, June 2001.

Speaker, Hale and Dorr Energy Group, Session on California and the Lessons for Massachusetts, Boston, MA, June 2001.

Speaker, Princeton University International Workshop on Privatization, Regulatory Reform, and Corporate Governance, Princeton, NJ, June 2001.

Speaker, EEL Transmission Policy Task Force Workshop, Milwaukee, WI, June 2001.

Speaker, 20th Annual Conference, Center for Research in Regulated Industries, Rutgers University, Tamiment, PA, May 2001.

Speaker, Conference on the Texas Electric Market and How It Compares to the California Market, University of Texas at Austin, TX, May 2001.

Speaker, NY State Associated Press Conference, Syracuse, N.Y., April 2001.

Speaker, American Power Conference, Chicago, IL, April 2001.

Conference Co-Chair, Harvard Electricity Policy Group Special Session, Cambridge, MA, April 2001.

Speaker, National Energy Marketers Conference, Washington, D.C., April 2001.

Speaker, Utilicon Conference, Auckland, New Zealand, March 2001.

Speaker, AEI/ Brookings Joint Center Conference, "The California Electricity Market Meltdown: The End of Deregulation?" Washington, D.C., March 2001.

Conference Co-Chair, Harvard Electricity Policy Group 25th Plenary Session, San Diego, CA, February 2001.

Conference Co-Chair, Speaker, Harvard-Japan Project on Energy and the Environment, Tokyo, January 2001.

Conference Co-Chair, Speaker, XI Repsol YPF - Harvard Seminar on Energy Policy, Buenos Aires, Argentina, December 2000.

Conference Co-Chair, Harvard Electricity Policy Group Special Session on RTOs, Houston, TX, December 2000.

Speaker, Infocast Conference on Congestion and Parallel Path Issues, Washington, D.C., November 2000.

Speaker: Energy Bar Association MidYear Meeting, Washington D.C., November 17, 2000.

Speaker, Northeast Power Coordinating Council, General Meeting 2000 on Restructuring Reliably, Boston, MA, September 2000.

Conference Co-Chair, Harvard Electricity Policy Group 23rd Plenary Session, Boston, MA, September 2000.

Speaker, IAAE Conference "Towards an Integrated European Energy Market," Bergen, Norway, August 2000.

Speaker, Workshop for Markets for Electricity Economics and Technology (MEET), Palo Alto, CA, August 2000.

Conference Co-Chair, Aspen Institute Energy Forum on the Future Structure of the Energy Industry, Aspen, CO, July 2000.

Speaker, Conference on "Market Surveillance in Ontario's Wholesale Electricity Market," Toronto, Ontario, Canada, June 2000.

Speaker, Conference on "The New Energy in the New Millennium in Asturias," Oveido, Spain, June 2000.

Speaker, Northeast Energy and Commerce Association Annual Conference: "Emerging Energy Markets: the Future is Now," Boxborough, MA, May 2000.

Conference Co-Chair, Harvard Electricity Policy Group 22nd Plenary Session, Cambridge, MA, May 2000.

Discussant, Brookings Conference on Economic Activity in Latin America, New York University, New York, NY, May 2000.

Speaker, EEI/ Energy Daily Conference on Market Monitoring, Washington, D.C., May 2000.

Keynote Speaker, National Regulatory Agency on Electrical Energy (ANEEL), Brazil, International Teleconference on Strategic Development, Belo Horizonte, Brazil and Cambridge, MA, April 2000.

Speaker, IIT/ American Power Conference 2000, "What Is the Optimum Structure for the Midwest Grid?" Chicago, Illinois, April 2000.

Speaker, International Bar Association, Section on Energy and Natural Resources Law 2000, Hong Kong, April 2000.

Speaker, Infocast Conference on Maximizing the Value of Transmission Assets," Washington, D.C., April 2000.

Speaker, POWER Research Conference on Electricity Industry Restructuring, University of California,

Berkeley, CA, March 2000.

Conference Co-Chair, Harvard Electricity Policy Group Special Session on Transition, Dallas, TX, March 2000.

Speaker, Christian A. Johnson Distinguished Lecture Series, "Making Markets for Power," Colby College, Waterville, ME, March 2000.

Speaker, Cantor Lecture Series 2000 on Energy and Society, Royal Society for the Encouragement of Arts, Manufactures & Commerce (RSA), London, UK, February 2000.

Speaker, Harvard-Japan Project on Energy and the Environment, Tokyo Conference, Tokyo, Japan, January 2000.

Conference Co-Chair, Speaker, Harvard Electricity Policy Group 21st Plenary Session, St. Helena, CA, January 2000.

Conference Co-Chair, Speaker: Harvard Electricity Policy Group Special Session on the State of the Wholesale Market: Reliability and Regional Trade, Chantilly, VA, November 1999.

Speaker, EEI Transmission Policy Task Force Meeting, Denver, CO, November 1999.

Speaker, Conference on the Impacts of Congestion Pricing on Competitive Markets, Washington, D.C., November 1999.

Speaker, Northeast Interregional ISO Coordination Conference, Albany, NY, October 1999.

Speaker, ISO New England Board of Directors Meeting, Chatham, MA, October 1999.

Conference Co-Chair, Speaker, Harvard Electricity Policy Group 20th Plenary Session, Newport, RI, September 1999.

Speaker, Utility Futures Group Seminar, Energy Foundation, Chicago, IL, September 1999.

Speaker, Session Chair, XX USAEE North American Conference, Orlando, FL, August 1999.

Speaker, XVII Latin American Meeting of the Econometric Society, Latin American Electricity Restructuring, Cancun, Mexico, August 1999.

Speaker, NARUC Summer Meeting, Electricity Committee Session, San Francisco, CA, July 1999.

Speaker, Executive Session on Infrastructure in a Market Economy, Kennedy School of Government, Harvard University, Cambridge, MA, July 1999.

Speaker, Executive Session on Environmental Economics and Policy Analysis, Harvard Institute for International Development, Harvard University, Cambridge, MA, July 1999.

Speaker, International Program on Privatization and Regulatory Reform, Harvard Institute for International Development, Harvard University, Cambridge, MA, July 1999.

Speaker, Workshop on the Introduction to Energy Economics and Policy, sponsored by the Department of Energy, Mexico, Mexico City, Mexico, June 1999.

Conference Co-Chair, Speaker, Harvard Electricity Policy Group 19th Plenary Session, Cambridge, MA, May 1999.

Speaker, Session Chair, Hudson Institute International Forum on Regulatory Policy: Regulators and the Regulated -- Making the Regulatory Process Work, Washington, D.C., April 1999.

Speaker, Conference on Independent Transmission Companies: A Better Alternative to ISOs? Las Vegas, NV, April 1999.

Speaker, Infocast Conference on Congestion Management, Washington, D.C., March 1999.

Conference Co-Chair, Harvard Electricity Policy Group, Special Session on Retail and Wholesale Transmission Markets, Washington, D.C., March 1999.

Speaker, Massachusetts Electric Restructuring Roundtable, Boston, MA, March 1999.

Speaker, New England Conference of Public Utilities Commissioners, Conference on Congestion Management, Nashua, NH, March 1999.

Speaker, ITAM Conference on Electricity Restructuring, Mexico City, Mexico, February 1999.

Speaker, EEI/Energy Daily Conference on Grid Regionalization, Washington, D.C., February 1999.

Speaker: IEEE Power Engineering Society Winter Meeting, New York, NY, February 1999.

Conference Co-Chair, Session Chair, Harvard Electricity Policy Group 18th Plenary Session: Retail Competition in Theory and in Practice, Carmel, CA, January 1999.

Speaker, Harvard-Japan Project on Energy and the Environment, Annual Conference, Tokyo, January 1999.

Speaker, Edison Electric Institute Chief Executive Conference, Phoenix, AZ, January 1999.

Session Chair, Speaker: Federal Energy Bar Association Mid Year Meeting, Washington, D.C., December 1998.

Conference Co-Chair, Speaker: Harvard Electricity Policy Group Special Seminar on Regional Boundaries, Regional Markets and Regional Institutions, Milwaukee, WI, November 1998.

Speaker, ICM Conference on ISOs, Chicago, IL, November 1998.

Speaker, Massachusetts Electric Utility Restructuring Roundtable, Boston, MA, October 1998.

Speaker, GPU Rate Conference, Short Hills, NJ, October 1998.

Keynote Speaker, Conference on Pricing and Tariffs: How Transmission Pricing and Constraints Will Impact Competitive Markets, Washington, D.C., September 1998.

Conference Co-Chair, Harvard Electricity Policy Group 17th Plenary Session, Cambridge, MA, September 1998.

Speaker, FACS Conference on Covering Electricity Restructuring, Bedford, MA, September 1998.

Speaker, Workshop on Environmental Economics & Policy Analysis, Harvard Institute for International Development, Cambridge, MA, July 1998.

Speaker, International Program on Privatization and Regulatory Reform, Harvard Institute for International Development, Cambridge, MA, July 1998.

Session Chair, Aspen Institute Program on Energy, the Environment, and the Economy, Aspen, CO, July 1998.

Speaker, Seminar on Electricity Deregulation, Universita della Svizzera Italiana, Lugano, Switzerland, June 1998.

Conference Co-Chair, Session Chair, IX Repsol-Harvard Seminar on Energy Policy: "Geopolitics, Energy and the Future," Santiago de Compostela, Spain, June 1998.

Keynote Speaker, Conference on Transmission Pricing, Denver, CO, June 1998.

Conference Co-Chair, Speaker, Harvard Electricity Policy Group 16th Plenary Session, on Looking to National Electric Restructuring Legislation, Cambridge, MA, May 1998.

Keynote Speaker, GE MAPS Users' Conference, Washington, D.C., May 1998.

Speaker, Province of Ontario, Market Design Committee, International Workshop on Electricity Restructuring, Toronto, Canada, May 1998.

Speaker, Conference on Antitrust and Anticompetitive Behavior: The New Rules of the Game for Electric Power, Washington, D.C., May 1998.

Conference Co-Chair, Harvard Electricity Policy Group and Managing the Atom Project: Workshop on Utility Restructuring and Nuclear Power, Boston, MA, April 1998.

Conference Co-Chair, Harvard Electricity Policy Group, Special Seminar on Independent System Operators, Portland, OR, April 1998.

Speaker, American Power Conference, 60th Annual Meeting, Technology: Focus for Competition and Globalization, Chicago, IL, April 1998.

Speaker, Progress and Freedom Foundation Conference on Creating Competitive Markets in Electricity: Progress in the States, Washington, D.C., March 1998.

Speaker, IEEE Power Engineering Society Winter Meeting, Tampa, FL, February 1998.

Speaker, LeBoeuf Lamb Greene & MacRae Seminar on the Introduction of Independent Power and the Restructuring of the Electricity Sector, San Francisco, CA, January 1998.

Conference Co-Chair, Harvard Electricity Policy Group, 15th Plenary Session, San Diego, CA, January 1998.

Speaker, Harvard-Japan Project on Energy and the Environment Tokyo Seminar, Tokyo, Japan, January 1998.

Speaker, NARUC-DOE Fifth National Electricity Forum, "Creating a New Industry," Washington, D.C., December, 1997.

Speaker, Conference on Antitrust and Anticompetitive Behavior, Washington, D.C., December 1997.

Speaker, Harvard-Ukrainian National Security Program, Harvard University, Cambridge, MA, December 1997.

Conference Co-Chair, Harvard Electricity Policy Group, Special Session on "Looking Ahead to the New Electricity Market: What Should Regulators Do?" Washington, D.C., November, 1997.

Speaker, USAEE North American Conference on International Energy Markets, Competition and Policy, San Francisco, CA, September 1997.

Conference Co-Chair, Harvard Electricity Policy Group 14th Plenary Session, San Diego, CA, September 1997.

Speaker, Energy Daily Annual Retail Competition Conference: Defining Yourself in the Retail Marketplace, Washington, D.C., September 1997.

Speaker, International Program on Privatization and Regulatory Reform, Harvard Institute for International Development, Cambridge, MA, July 1997.

Speaker, Workshop on Environmental Economics and Policy Analysis, Harvard Institute for International Development, Cambridge, MA, July 1997.

Conference Co-Chair, VIII Repsol-Harvard Seminar on International Energy Markets, Seville, Spain, June 1997.

Keynote Speaker, Midwest Governors' Conference Annual Meeting, Kansas City, KN, June 1997.

Speaker, Seminar on International Electricity Restructuring, University of Zurich, Switzerland, May 1997.

Speaker, New England Conference of Public Utility Commissioners, 50th Symposium, Newport, RI, May 1997.

Speaker, Meeting on Locational Marginal Pricing, Electric Clearing House, Houston, TX, May 1997.

Speaker, *The Electricity Journal* and National Economic Research Associates, Conference on Restructuring '97, Amelia Island, FL, April 1997.

Speaker, University of California Energy Institute, POWER Conference on Electricity Restructuring, Berkeley, CA, March 1997.

Speaker, Electric Power Research Institute, Workshop on Markets for Electricity: Economics and Technology, Stanford, CA, March 1997.

Conference Co-Chair, Harvard Electricity Policy Group, Seminar on Public Sector Strategies in a Restructured Electricity Industry, Nashville, TN, March 1997.

Speaker, Asia-Pacific Energy Forum, Sixth East Asia Electricity and Gas Forum, Tokyo, Japan, January 1997.

Speaker, Harvard-Japan Project on Energy and the Environment, Tokyo Conference, Tokyo, Japan, January 1997.

Conference Co-Chair, Harvard Electricity Policy Group, Plenary Session on ISO Governance, La Quinta, CA, January 1997.

Speaker, Massachusetts General Court Special Committee on Electric Utility Restructuring, Conference on Massachusetts Restructuring, Cambridge, MA, December 1997.

Speaker, Michigan State University Institute of Public Utilities, Conference on Surviving Regulatory Change and Competition, Williamsburg, VA, December 1997.

Speaker, Commonwealth of Virginia State Corporation Commission, Virginia Electricity Forum, Charlottesville, VA, November 1996.

Conference Co-Chair, Harvard Electricity Policy Group, Seminar on Regional Regulation, Cincinnati, OH, November 1996.

Keynote Speaker, Conference on Strategies for Structuring, Governing, and Operating Independent System Operators, Chicago, IL, October 1996.

Speaker, Southern Company College, Course on Emerging Competitive Energy Markets, Atlanta, GA, September 1996.

Conference Co-Chair, Harvard Electricity Policy Group, Plenary Session on Electricity Restructuring, Boston, MA, September 1996.

Speaker, Stockholm School of Economics, Conference on the Transition to a Deregulated and International Market for Electricity, Stockholm, Sweden, August 1996.

Speaker, National Association of Regulatory Utility Commissioners, Conference on ISOs and Regulation, Los Angeles, CA, July 1996.

Speaker, American Gas Association, Conference on Electric Industry Restructuring and FERC Order 888, Arlington, VA, July 1996.

Speaker, Aspen Institute Summer Energy Policy Forum, Aspen, CO, July 1996.

Speaker, Harvard Institute for International Development, Workshop on Environmental Economics and Policy Analysis, Cambridge, MA, June 1996.

Conference Co-Chair, Harvard Electricity Policy Group, Plenary Session on ISO Governance, Boston, MA, June 1996.

Speaker, Mid-America Regulatory Commissioners Conference, Assessing the Winds of Change, Chicago, IL, June 1996.

Conference Co-Chair, Speaker, Harvard Electricity Policy Group, Plenary Session, Boston, MA, June 1996.

Speaker, Special Libraries Association, Annual Meeting, Boston, MA, June 1996.

Conference Co-Chair, Speaker, Repsol-Harvard Seminar on Energy Policy, Granada, Spain, May 1996.

Speaker, New England Conference of Public Utilities Commissioners, Annual Symposium, Manchester, VT, May 1996.

Speaker, Federal Energy Bar Association, Annual Meeting, Washington, D.C., May 1996.

Conference Co-Chair, Speaker, Harvard Electricity Policy Group, Session on Residual Monopoly Services, Pittsburgh, PA, April 1996.

Speaker, U.S. Department of Justice/ Federal Trade Commission Workshop on Electricity Restructuring, Washington, D.C., April 1996.

Speaker, Centre for Global Energy Studies, Sixth Annual Conference, London, UK, April 1996.

Speaker, Electric Policy Research Institute, Conference on Innovative Approaches to Electricity Pricing, La Jolla, CA, March 1996.

Speaker, Harvard-Japan Project on Energy and the Environment, Tokyo Conference, Tokyo, Japan, January 1996.

Speaker, East Asian Electricity Restructuring Forum Conference, Bangkok, Thailand, December 1995.

Speaker, IEEE International Forum on Deregulation and Re-structuring in the Electric Power Sector, Belo Horizonte, Brazil, November 1995.

Speaker, Seminar on the Revolution in the Electric Power Industry, Carnegie Mellon University, Pittsburgh, PA, November, 1995.

Speaker, The New Hampshire General Court, The Retail Wheeling and Restructuring Study Committee, Concord, NH, November, 1995.

Speaker, Energy Policy Seminar, American Enterprise Institute, Washington, D.C., November, 1995.

Speaker, Indiana Energy Conference, Indianapolis, IN, November 1995.

Speaker: INFORMS National Meeting, New Orleans, LA, October 1995.

Conference Co-Chair, Speaker, Harvard Electricity Policy Group Plenary Session, Chicago, IL, October 26-27, 1995.

Speaker, MIT Conference on Keeping the Lights On: Technical and Institutional Issues in a Restructured Electricity Industry, Cambridge, MA, October 1995.

Speaker, The Energy Council of Rhode Island, Annual Membership Meeting, Warwick, RI, October 1995.

Session Chair, Ninth Annual Northeast Electricity Policy Executive Session, Lenox, MA, October 1995.

Speaker, EPRI Conference on Achieving Success in Evolving Electricity Markets, Atlanta, GA, October 1995.

Speaker, North American Electric Reliability Council, Board of Trustees Meeting, Princeton, NJ, October 1995.

Speaker, National Conference of State Legislatures, Videoconference on Fuel for a Competitive Northeast, Washington, D.C., September 1995.

Speaker, Center for Business Intelligence, Conference on Valuing and Recovering Stranded Costs in the New Age of Competitive Power, Washington, D.C., September 1995.

Speaker, Jefferson Energy Foundation, Conference on Energy and Power: Succeeding in the New Competitive

Era, Washington, D.C., September 1995.

Speaker, Institute for International Research, Conference on Transmission Access and Pricing: Responding to the FERC Mega NOPR, Washington, D.C., September 1995.

Speaker, Energy Generation Association, Summer 1995. Meeting, White Sulfur Springs, WV, July 1995.

Speaker, Aspen Institute on Energy, Environment, Economy, Conference on Electric Utility Industry Restructuring, Aspen, CO, July 1995.

Session Chair, International Association for Energy Economics, 18th International Conference, Washington, D.C., July 1995.

Speaker, Harvard Institute for International Development, Workshop on Energy Economics and Policy Analysis, Cambridge, MA, June 1995.

Conference Co-Chair, Speaker, Repsol-Harvard Seminar on International Energy Markets, S'Agaro, Spain, June 1995.

Speaker, University of Zurich, Institute for Economic Research, Seminar on Electricity Markets, Zurich, Switzerland, June 1995.

Speaker, East Asian Electricity Restructuring Forum, Beijing, China, May 1995.

Speaker, American Enterprise Institute, Energy Policy Forum, Washington, D.C., May 1995.

Conference Co-Chair, Speaker, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, May 1995.

Keynote Speaker, Public Utilities Research Center, University of Florida, Annual Conference on Market and Technological Convergence: Implications for Regulation, Gainesville, Florida, April 1995.

Speaker, Oak Ridge National Laboratories, Seminar on Electricity Transmission and Emerging Competition, Oak Ridge, Tennessee, April 1995.

Speaker, New Jersey Board of Public Utilities, Electric Power Industry Conference, Newark, N.J., March 1995.

Speaker, Electricity Consumers Resource Council, Workshop on Pools, Washington, D.C., February 1995.

Speaker, DOE National Energy Modeling Systems/ AEO Conference, Washington, D.C., February 1995.

Speaker, East Asian Electricity Restructuring Forum, Tokyo, January 1995.

Speaker, Harvard-Japan Conference on Energy and Environment, Tokyo, January 1995.

Conference Co-Chair, Speaker, Harvard Electricity Policy Group Plenary Session, New Orleans, Louisiana, January 1995.

Speaker, New Jersey Board of Public Utilities, Conference on Electric Utility Restructuring, Newark, New Jersey, December 1994.

Speaker, Michigan State University, Institute of Public Utilities, 1994. Annual Conference, Williamsburg, VA, December 1994.

Speaker, New England Governors' Conference, Inc., Power Planning Committee, Meeting with New England Conference of Public Utilities Commissioners, Durham, NH, November 1994.

Speaker, University of Toronto, Faculty of Law, Seminar and Presentations, Toronto, Canada, November 1994.

Speaker, Federal Energy Bar Association, Mid Year Meeting on Turmoil for the Utilities, Washington, D.C., November 1994.

Speaker, U.S. Department of Energy/National Association of Regulatory Utility Commissioners, National Electricity Forum, Washington, D.C., November 1994.

Speaker, Association of Edison Illuminating Companies, Power Generation Committee, Meeting, Boston, MA, October 1994.

Speaker, Edison Electric Institute, Fall Legal Conference, New Orleans, Louisiana, October 1994.

Speaker, National Independent Energy Producers, Fall Conference, White Sulfur Springs, West Virginia, October 1994.

Speaker, Wisconsin Public Utility Institute, Conference on Public Policies toward Competition in the Electric Power Industry, Madison, Wisconsin, October, 1994.

Speaker, American Enterprise Institute, Energy Policy Forum, Washington, D.C., September 1994.

Speaker, Energy Daily Conference on The Impact of Retail Competition on the Electric Markets, San Diego, CA, September 1994.

Speaker, Southern Company Executive Forum, Atlanta, Georgia, September 1994.

Session Chair, Aspen Institute Workshop on the Electric Industry Moves Into Competitive Markets, Aspen, Colorado, July 1994.

Speaker, National Association of Regulatory Utility Commissioners Committee on Electricity, Summer Meeting, San Diego, CA, July 1994.

Speaker, New York State Energy Research and Development Authority and Niagara Mohawk Conference on The Electric Industry in Transition, Albany, New York, June 1994.

Co-Chair, Speaker, Repsol-Harvard Conference on World Oil Markets, Barcelona, Spain, June 1994.

Speaker, TAPS Conference on Transmission, Washington, D.C., May 1994.

Speaker, Exnet Conference on Transmission Access and Pricing, Washington, D.C., April 1994.

Speaker, Joint Institute for Energy & Environment, University of Tennessee, Conference on Twenty Years After the Energy Shock: How Far Have We Come? Where Are We Headed? Knoxville, Tennessee, April 1994.

Speaker, Digital Equipment Corporation and Duke Engineering Conference on Utilities 2000, The Challenge of Change, Charlotte, North Carolina, March 1994.

Session Chair, National Independent Energy Producers Winter Meeting, Washington, D.C., January 1994.

Speaker, Harvard-Japan Project Conference on Energy and the Environment, Tokyo, Japan, January 1994.

Conference Co-Chair, Speaker, Harvard Electricity Policy Group Plenary Session, San Diego, CA, January 1994.

Speaker, California Foundation on the Environment and the Economy, Executive Briefing on the British Electrical Energy System, San Francisco, CA, January 1994.

Speaker, Northeast Utilities Executive Planning Conference, Westbrook, Connecticut, November 1993.

Conference Co-Chair, Speaker, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, October 1993.

Session Chair, Harvard Northeast Utility Policy Executive Session, Southbury, Connecticut, October 1993.

Speaker, Canadian Association of Members of Public Utility Tribunals, Annual Conference, Ottawa, Canada, September 1993.

Speaker, Harvard University Fairbank Center Meeting, Economic Development in Southeast Asia, New York, September 1993.

Speaker, Session Chair, International Association for Energy Economics, Annual International Conference, Bali, Indonesia, July 1993.

Session Chair, Aspen Institute, Policy Issue Forum on Energy, Environment, and the Economy, Aspen, Colorado, July 1993.

Conference Co-Chair, Speaker, Harvard Electricity Policy Group Plenary Session, Cambridge, MA, July 1993.

Speaker, Center for Regulatory Studies, University of Illinois, Conference on Electric Transmission in the 1990s, Oak Brook, Illinois, May 1993.

Speaker, American Enterprise Institute, Energy Policy Forum, Washington, D.C., May 1993.

Speaker, Edison Electric Institute, Finance Committee Annual Meeting, New York, May 1993.

Participant, U.S. Office of Technology Assessment, Conference on Climate Treaties and Models, Washington, D.C., April 1993.

Speaker, Conference on Regional Transmission Groups: Creation, Regulation, Access, and Pricing, Washington, D.C., March 1993.

Speaker, American Bar Association Conference on Electricity Law and Regulation, Denver, Colorado, February 1993.

Speaker, Harvard-Japan Project Conference on Energy and the Environment, Tokyo, Japan, January 1993.

Speaker, Coopers & Lybrand Electric and Gas Industry Key Issues Forum, McLean, Virginia, December 1992.

Speaker, University of Rochester, W. Allen Wallis Institute of Political Economy, Inaugural Lecture Program,

Rochester, New York, December 1992.

Speaker, Digital Equipment Corporation Conference on Achieving Business Excellence in Utilities, Atlanta, Georgia, November 1992.

Speaker, University of Toronto, Conference on The Post-Communist Transformation: Emerging Economic, Legal, and Business Implications, Toronto, October 1992.

Session Chair, Center for Business and Government, Harvard University, Northeast Electric Utility Policy Executive Session, Cooperstown, New York, October 1992.

Panel Member, Brookings Panel on Economic Activity, Brookings Institute, Washington, D.C., September 1992.

Speaker, Conference on Energy Cooperation in Central Asia and the Caucasus, Teheran, Iran, September 1992.

Speaker, Aspen Institute Forum on Environmental Policy and Governance: Economic Implications and Energy System Impacts, Aspen, Colorado, August 1992.

Speaker, Conference on Ukraine: The New Business Partner, Kiev, Ukraine, June 1992.

Speaker; Session Chair, IAEE Conference on Coping with the Energy Future: Markets and Regulations, Tours, France, May 1992.

Speaker, POWER Conference on Innovative Approaches to Energy and Environmental Planning in CA, Sacramento, CA, April 1992.

Speaker, International Bar Association, Section on Energy and Natural Resources Law Conference, Washington D.C., April 1992.

Session Chair Conference on Market-Based Mechanisms for Addressing Global Climate Change, Washington D.C., March 1992.

Speaker, National Independent Energy Producers Membership Meeting, Washington, D.C., January 1992.

Speaker, Harvard-Japan Conference on Energy and the Environment, Tokyo, Japan, January 1992.

Speaker, Symposium on Strategic Security of Ukraine, Kiev, Ukraine, December 1991.

Speaker, Royal Institute of International Affairs, Conference on Energy Policy: Market-Led or Government-Driven? London, December 1991.

Speaker, International Association of Energy Economics, North American Conference, Chicago, Illinois, November 1991.

Speaker, Edison Electric Institute, Strategic Planning Services Committee, Fall Conference, Washington D.C., November 1991.

Session Chair, Center for Business and Government, Harvard University, Northeast Electric Utility Policy Executive Session, Killington, Vermont, October 1991.

Speaker, Institute for East-West Security Studies Meeting on Economic Reform in Ukraine, New York, October 1991.

Speaker, Brookings Panel on Economic Activity, Symposium on the Soviet Economy after Communism, Brookings Institute, Washington, D.C., September 1991.

Speaker, American Bar Association, Section on Public Utility, Communications, and Transportation Law, Atlanta, Georgia, August 1991.

Speaker, Aspen Institute Forum on Oil, Energy Policy and National Security--After the Gulf Crisis, Aspen, Colorado, July 1991.

Speaker, Harvard-Repsol Conference on Oil Markets in the 1990s, Segovia, Spain, June 1991.

Conference Co-Chair, Project on Economic Reform in Ukraine, Conference on Military Conversion, Kiev, Ukrainian SSR, May 1991.

Speaker, Workshop on Social and Political Consequences of Decentralization and Privatization, Gdansk, Poland, April 1991.

Speaker, Harvard-Japan Project Conference on Energy and the Environment, Tokyo, Japan, January 1991.

Speaker, Conference on Infrastructure for the 1990.s, Harvard University, Cambridge, MA, November 1990.

Conference Co-Chair, Conference on Economic Reform in Ukraine, Harvard University, Cambridge, MA, November 1990.

Speaker, Workshop on Economic/Energy/Environmental Modeling for Climate Policy Analysis, MA Institute of Technology, Washington, D.C., November 1990.

Speaker, California Foundation on the Environment and the Economy, Conference on Electricity, Monterey, CA, May 1990.

Speaker, Independent Petroleum Association of America, Conference on Supply and Demand, Boston, MA, May 1990.

Speaker, Vinson & Elkins Seminar on Oil Markets, Houston, Texas, April 1990.

Speaker, American Gas Association Seminar on Gas Demand Modeling and Forecasting, Houston, Texas, February 1990.

Speaker, Harvard-Japan World Oil Market Study Seminar, Tokyo, Japan, January 1990.

Speaker, Harvard-Repsol Conference on International Energy, Toledo, Spain, November 1989.

Speaker, International Symposium on Petroleum Economics, Laval University, Quebec, September 1989.

Speaker, IAEE Conference on North American Natural Gas Supply and Markets, Denver, Colorado, September 1989.

Speaker, Harvard Utility Forum/ Harvard Gas Forum Seminar, Energy and Environmental Policy Center, Harvard University, Cambridge, MA, June 1989.

Speaker, California Public Utilities Commission, Workshop on Capacity Priority Allocation, San Francisco, CA, June 1989.

Conference Chair, Speaker, International Oil and Gas Conference, Energy and Environmental Policy Center, Harvard University, Cambridge, MA, June 1989.

Speaker, U.S. House of Representatives Energy Security Working Group meeting, Washington, D.C., May 1989.

Speaker, Federal Energy Regulatory Commission Hearings on Firm Natural Gas Transportation and Priority Capacity Allocation, Washington, D.C., March 1989.

Speaker, First Boston/Putnam, Hayes & Bartlett Utility CEO Forum, Key Largo, Florida, February 1989.

Speaker, Harvard Utility Forum/Harvard Gas Forum Seminars, Energy and Environmental Policy Center, Harvard University, Cambridge, MA, February 1989.

Speaker, American Bar Association, Electric Utilities Group, Conference on Electricity Pricing, San Francisco, CA, January 1989.

Speaker, Institut Francais du Petrole, Seminar on World Oil Markets, Paris, France, December 1988.

Speaker, Southwestern Legal Foundation, National Institute on Natural Gas Law, Dallas, TX, Nov. 1988.

Speaker, Putnam, Hayes and Bartlett Seminar on Law and Economics, Phoenix, Arizona, September 1988.

Speaker, Harvard-Japan World Oil Market Study Seminar, Tokyo, Japan, September 1988.

Session Chair, Gas Research Institute Energy Seminar, Hilton Head, South Carolina, August 1988.

Speaker, Oklahoma Independent Petroleum Association Conference, Tulsa, Oklahoma, July 1988.

Speaker, National Academy of Engineering Symposium on An Energy Agenda for the 1990s, Beckman Center, Irvine, CA, May 1988.

Speaker, Harvard-Repsol Seminar on International Energy, Toledo, Spain, April 1988.

Speaker, EEP/ Texas Oil and Gas Seminar, Dallas, Texas, March 1988.

Speaker: University of Houston Conference on Oil Tariff Policy, Houston, Texas, March 1988.

Speaker, Harvard Utility Forum/ Harvard Gas Forum Seminar, Palm Beach, Florida, February 1988.

Speaker, Southern Economic Association Conference, Session on the Future of OPEC, Washington, D.C., November 1987.

Speaker, Boston Gas Company Planning Conference, New Seabury, MA, October 1987.

Speaker, Ashland Exploration Company Conference on Oil Market Development, San Antonio, Texas, October 1987.

Speaker, Harvard-Japan Project on International Oil, Seminar, Tokyo, Japan, October 1987.

Session Chair, Harvard Executive Session on Northeast Electric Power Policy, Martha's Vineyard, MA, September 1987.

Speaker, American Jewish Congress Governing Council, Effects of an Oil Tariff, New York, New York, September 1987.

Speaker, Stockholm School of Economics Seminar on International Energy Demand, Stockholm, Sweden, August 1987.

Session Chair, International Association of Energy Economists North American Conference on The Growth of Risk, Calgary, Canada, July 1987.

Speaker, South Texas College of Law, Advanced Oil and Gas Course, Houston, Texas, June 1987.

Speaker, New York University Energy Forum on U.S. and World Oil Reserves, New York, New York, June 1987.

Speaker, Potomac Electric Power Company Conference on Future Fuel Prices, Washington D.C., May 1987.

Speaker, International Oil and Gas Conference on Energy Security Revisited, Energy and Environmental Policy Center, Harvard University, Cambridge, MA, May 1987.

Speaker, Harvard/Federal Energy Regulatory Commission Seminar on Natural Gas Regulation, Cambridge, MA, May 1987.

Speaker, Northwestern University Conference on Petroleum Economics and Management, Evanston, Illinois, April 1987.

Speaker, Harvard Japan Oil Market Study Workshop, Harvard University, Cambridge, MA, March 1987.

Speaker, Washington Energy Conference on U.S. Energy Security, Johns Hopkins University School of Advanced International Studies, Washington, D.C., March 1987.

Panelist: Conference on Venezuela/ Energy Issues, Harvard Institute for International Development, Cambridge, MA, March 1987.

Speaker, Conference on Oil Tariff Policy, Washington D.C., December 1986.

Speaker, Session Chair, International Association of Energy Economists Eighth Annual North American Conference on the Changing World Energy Economy, Cambridge, MA, November 1986.

Speaker: Cabot Corporation Seminar on International Investments and Operations, Boston, MA, Oct. 1986.

Session Chair, World Energy Conference, 13th Congress, on Energy: Needs and Expectations, Cannes, France, October 1986.

Speaker, Session Chair, Harvard Executive Session on Northeast Electric Power, Martha's Vineyard, MA, September 1986.

Speaker, Aspen Institute Summer Forum on the Policy Implications of Declining Oil Prices, Aspen, Colorado, August 1986.

Speaker, The Johns Hopkins School of Advanced International Studies/ IAAE Workshop on The Oil Price Collapse: Impact on Demand, Washington, D.C., June 1986.

Speaker, Electric Power Research Institute Conference, Williamsburg, Virginia, May 1986.

Session Chair, Harvard International Oil Conference on Managing Oil Market Risk, Cambridge, MA, May 1986.

Speaker, RAND Conference on International Economic Surprises, Santa Monica, CA, December 1985.

Session Chair, EPRI/Harvard Workshop on Risk Management: Charting A Research Agenda for the Future, Cambridge, MA, October 1985.

Speaker, Executive Seminar at Stanford University: Energy Decisionmaking in the 80s, Stanford, CA, July 1985.

Speaker, Industrial Bank of Japan, Middle East Seminar, Tokyo, June 1985.

Speaker, International Association of Energy Economists Conference, Bonn, Federal Republic of Germany, June 1985.

Speaker, Interstate Natural Gas Association of America Conference, Colorado Springs, April 1985.

Speaker, Synfuels '85 Conference, sponsored by the National Council on Synthetic Fuels Production and Synthetic Fuels Research Institute, Hilton Head, South Carolina, April 1985.

Participant, Stanford University Trinational Energy Policy Workshop, Stanford CA, February 1985.

Speaker, Brookhaven Conference on Energy Planning Under Uncertainty, Brookhaven, New York, August 1984.

Speaker, RFF Conference on Energy Security, Washington, D.C., June 1984.

Speaker, Nordic Council Meeting on Energy Planning Under Uncertainty, Kungälv, Sweden, June 1984.

Speaker, Energy Bar Association, Washington, D.C., January 1984.

Speaker, American Economics Association, December 1983.

Speaker, ORSA/TIMS Meeting, Chicago, Illinois, November 1983.

Speaker, National Defense University, Washington, D.C., 1983.

Speaker, Stanford University Executive Session on Energy Investments in the 1980s, Stanford, CA, 1982.

Speaker, ORSA/TIMS, Joint National Meeting, CA, 1982.

Speaker, Brookings Institute Seminar, Washington, D.C., 1982.

Speaker, Workshop on Energy Policy in the US and China, Peoples Republic of China, 1982.

Speaker, Energy and Security Workshop, Tokyo, Japan, 1982.

Speaker, Department of Energy Symposium on DOE's New Integrated Forecasting System, Washington, D.C., 1982.

Speaker, Harvard University, Kennedy School of Government, Conference on Energy and Security in the 1980s, Cambridge, MA, 1982.

Speaker, Harvard University, Kennedy School of Government Executive Session on Nuclear Power and Energy Availability, Cambridge, MA, 1982.

Member, Synthetic Fuels Study Panel, Synthetic Fuels Corporation, 1982.

Speaker, Institute of Gas Technology, Conference on Energy Modeling, 1982.

Speaker, IAEE Panel on Synthetic Fuels Policy, Houston, Texas, 1982.

Speaker, European American Institute, 1981.

Speaker, Security Conference on Asia and the Pacific, 1981.

Speaker, Volvo Conference on European Energy Needs, 1981.

Speaker, Stanford Conference on Energy Productivity, Stanford, CA, 1981.

Speaker, Symposium on Modeling of Large-scale Systems, IIASA, Laxenburg, Austria, 1980.

Speaker, University of Southern CA, Center for the Study of the American Experience, Annenberg School of Communications, Conference on America in an Era of Plentiful But Higher-Priced Energy, 1979.

Speaker, TIMS/ORSA Meeting, New Orleans, Louisiana, 1979.

Discussant, Resources for the Future/NSF Conference on the Implications of Potential Resource and Environmental Constraints for Growth, San Francisco, CA, 1979.

Session Chair, The Institute of Management Sciences XXIV International Meeting, Honolulu, Hawaii, 1979.

Speaker, Alliance to Save Energy, Symposium, Dumbarton Oaks, Virginia, 1979.

Program Co-Chair, IAEE/RFF Conference on International Energy Issues, Washington D.C., 1979.

Speaker, Aspen Institute Conference on Governmental Issues Concerned with the Siting of Nuclear Waste, Aspen, Colorado, 1979.

Speaker, Triennial Meeting of the International Federation of Operations Research Societies, Toronto, Canada, 1978.

Speaker, Bay Area Chapter, International Association of Energy Economists, San Francisco, CA, 1978.

Speaker, 5th Annual Energy Technology Conference, Washington, D.C., 1978.

Speaker, IEEE Conference, New Orleans, 1977.

Speaker, American Economics Association Conference, New York, 1977.

Speaker, Annual Meeting of National Association of Business Economists, 1977.

Participant, Program Committee, Lawrence Symposium on Systems and Decision Sciences, 1977.

Speaker, TIMS Conference on Energy and the Economy, San Francisco, 1977.

Speaker, American Mathematical Society Short Course on Energy, 1976.

Participant, Washington Operations Research Council, 1976.

Participant, National Petroleum Refiners Association, 1975.

Participant, TIMS New York Regional Chapter, 1975.

Speaker, Energy Analysis Meeting of International Federation of Institutes of Advanced Study, 1975.

Participant, Friends of Optimization, 1975.

Participant, ORSA/TIMS Conference, Panel on Energy Use, New York, 1975.

Session Chair, ORSA/TIMS Conference, Panel on Large Energy Models, Las Vegas Nevada, 1975.

Attachment C
Exhibit 3

Pope CV
March 29, 2019



Susan Pope

Managing Director

Susan.Pope@fticonsulting.com

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9th Floor
Boston, MA 02109
Tel: (617) 747 - 1860

Education

A.B. *cum laude* in
Applied Mathematics,
Harvard University

Ph.D. and M.A. in
Business Economics,
Harvard University

Susan Pope is a Managing Director at FTI Consulting and is based in Boston. Dr. Pope is in the Economic Consulting Practice and specializes in the economic and public policy analysis of electricity markets by advising clients on the design, improvement and performance of bid-based electricity spot markets, capacity markets, and ancillary service markets.

Dr. Pope worked with the New York Power Pool on the development of the New York ISO and the LMP-based electricity markets implemented in November 1999, with ISO-New England on the development of its electricity markets implemented in 2003, with the Midcontinent ISO on the development of its Stage 2 congestion management market implemented in 2005, and with the California ISO on its market redesign implemented in 2009.

She and her colleagues have been actively supporting the Ontario IESO on the redesign of its energy and ancillary services markets. She also recently wrote a paper assessing energy price formation in ERCOT, submitted testimony in Alberta concerning their proposed Comprehensive Market Reform, and advised the Public Utility Authority of Israel on the design and introduction of competitive electricity markets.

PROFESSIONAL EXPERIENCE

- *FTI Consulting*, Managing Director, Boston MA, 2011 – Present
- *LECG*, Principal, Cambridge MA, 1998 – 2011
- *Putnam, Hayes & Bartlett*, Associate and Principal, Cambridge MA, 1989 – 1998

SELECTED PROJECTS

Electric Utility Experience

- Supporting the Independent Electric System Operator of Ontario in the detailed design of a single settlement real-time electricity market and a financially binding day-ahead market.
- Submitted written evidence as an independent expert to the Alberta Utilities Commission regarding the proposal by the Alberta Electric System Operator to introduce a market for installed capacity in Alberta.
- Advised the senior staff of Israel's Public Utility Authority – Electricity on electricity market reforms, with a focus on how to support efficient supply under existing contracts and for future capacity needs.
- On behalf of the Australian Energy Market Operator, worked with colleagues in the United Kingdom to write a report about alternative approaches to transmission planning and cost recovery, see <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Planning-and-network-regulation>.
- Co-authored a critique of a recent decision by the Agency for the Cooperation of Electricity Regulators (European Union) concerning a proposal by AQUIND for a non-regulated transmission

interconnector between England and France.

- On behalf of an Australian client, supported colleagues in the United Kingdom in writing a report comparing wholesale electricity market designs, focusing on different approaches to transmission congestion management and capacity mechanisms in PJM, CAISO, Great Britain and Europe.
- Prepared a paper for the Natural Gas Supply Association assessing the implications for natural gas suppliers of PJM's proposed enhancements (2017) to its energy price formation
- For Powerex, co-authored a paper on the challenges of estimating opportunity costs to efficiently mitigate the local market power of energy-limited energy imbalance market resources.
- On behalf of two of the largest U.S. electricity suppliers, evaluating price formation in ERCOT's real-time electricity market and preparing a white paper for presentation to the Public Utility Commission of Texas.
- Supported the Independent Electric System Operator of Ontario in the high-level design of a single settlement real-time electricity market and a financially binding day-ahead market and unit commitment; co-led stakeholder meetings to discuss and determine elements of the design.
- Provided economic analysis and testimony to support a client in a proceeding addressing proposed changes to PJM's market rules for FTR settlements; represented client at FERC technical conference.
- Directed a team to provide expert economic support concerning the operation of western electricity markets and long-term electricity price forecasts for southern California for a significant arbitration concerning the closure of a large generating facility.
- Provided economic analysis to support a client anticipating litigation related to the New York Public Service Commission's proposal to pay certain nuclear generating units in the state for Zero Emission Credits (ZECs).
- Advised a coalition of financial marketers in FERC proceedings investigating the costs and benefits of financial bidding in the PJM market and the potential impacts on uplift.
- Assisted an eastern ISO in evaluating the economic and reliability impacts of the addition or removal of local capacity zones, and the process for determining zones, local capacity requirements and related cost allocations.
- Led a meeting of the Board of Portland General Electric (PGE) to discuss efforts to form an energy imbalance market in the Pacific Northwest and PGE's plans to join the California ISO Energy Imbalance Market.
- Provided expert economic support over many months to committees of the Northwest Power Pool evaluating the possible implementation of an energy imbalance market; supported meetings with FERC staff.
- Led an international team of economic experts engaged to design all aspects of the electricity market rules to restructure the electricity market in Mexico; wrote draft electricity market rules.
- Provided expert testimony concerning PJM's application of its hybrid cost allocation methodology to new baseline transmission project totaling almost \$1 billion.
- Completed a white paper for the Electric Power Supply Association (EPSA) explaining problems

with ISO/RTO price formation and recommending possible improvements; represented EPSA in FERC technical workshop on price formation.

- Assisted a large power trading client in evaluating the regulatory and strategic implications of the “resource shuffling” provisions of the California Air Resource Board’s cap-and-trade program for CO₂ emissions.
- Provided economic support and developed estimates of renewable generation costs in a dispute before the World Trade Organization pertaining to Feed in Tariffs for renewable energy in the Province of Ontario.
- Led project team analyzing market bidding behavior in California and Western electricity markets during the Western power crisis in 2000 and assisted in preparation of significant testimony on behalf of the Competitive Supplier Group in Docket No. EL00-95-248.
- Provided economic analysis and testimony to support a client anticipating potential Federal Energy Regulatory Commission (FERC) enforcement action related to its bids into the forward capacity market in ISO New England.
- Provided expert economic support for several significant expert reports for a client under investigation by the FERC Office of Enforcement in relation to its bids at an ISO intertie.
- Completed an affidavit for the Electric Power Supply Association (EPSA) responding to a FERC Notice of Proposed Rulemaking concerning sub-interval pricing and shortage pricing trigger intervals in real-time electricity markets.
- Assisted an eastern ISO in designing proposed tariff rules to evaluate the need for reliability must run units and to compensate units with reliability must run contracts.
- Provided testimony for Dynegy Market and Trade, LLC and Illinois Power Marketing Company concerning competitive behavior and the clearing price in Zone 4 in the Midcontinent ISO’s 2015/2016 annual capacity auction.
- Provided expert economic support to a large eastern utility concerning the implementation of PJM’s interim capacity market auctions, which it is using during the transition to its performance incentive capacity market design.
- Advised a large power trader on issues of market design and regulatory strategy resulting from the impact of the California ISO Energy Imbalance Market on existing transmission rights in the Pacific Northwest.
- Provided advisory services to a financial marketer seeking to improve price formation in ISO New England; represented client in meetings with industry groups (generators, financial marketers and state regulators) and with the ISO.
- Led a project team to provide testimony for a group of electricity suppliers pertaining to the supply and demand for electricity in the Pacific Northwest during the Western power crisis in 2000-2001; see Docket No. EL01-10-085.
- Provided testimony for NRG concerning ISO New England’s pay-for-performance modifications to its capacity market rules.
- Provided economic support concerning the dispatch offer price for the coal units of a Midwestern utility, and the treatment of contract costs versus market prices in retail rates.
- Assisted in the analysis of the impact on capacity prices of the possible creation of a new

downstate capacity zone in the NYISO.

- Provided economic support concerning the design of market mechanisms to maintain long-term electricity supply reliability in ERCOT, focusing on the role of operating reserve demand curves.
- Provided economic analysis and testimony for a financial marketer facing a FERC enforcement investigation of its trading activities in two ISOs.
- Provided analyses and regulatory support regarding Order 1000 (transmission planning and cost recovery) and PJM resource planning processes for an independent transmission company in the eastern U.S.
- Prepared, along with Scott M. Harvey and William W. Hogan, an evaluation of a number of aspects of the NYISO capacity market and provided recommendations for areas of improvement.
- Prepared testimony concerning exceptional dispatch in the CAISO; see Docket No. ER12-2539-000.
- Prepared an assessment of level of granularity of the settlements for loads within the eastern ISOs.
- Prepared a public assessment, along with Scott M. Harvey, of several proposals for the allocation of the costs of a large interstate transmission project in the MISO. Attended meetings with the MISO, stakeholders and regulators to discuss cost allocation for the Multi-Value project.
- Worked with the Midcontinent ISO and William W. Hogan to develop a theoretical and computational approach to establishing energy prices that would minimize the uplift arising in the implementation of competitive electricity markets.
- Prepared a report, with Scott M. Harvey, on the methodologies that the eastern ISO use to calculate settlements for loads, the rationale for and regulatory history of the different approaches, and the changes that have occurred over time.
- Assisted the ISO/RTO Council in preparing their 2009 State of the Market Report.
- Prepared a paper (with Scott M. Harvey) for the MISO describing ISO practices for scheduling transmission outages and a methodology for charging transmission owners for the congestion rent shortfall costs associated with transmission outages.
- Assisted the NYISO in developing proposals for future enhancements to their TCC markets.
- Assisted the NYISO in developing a methodology to charge for revenue shortfalls that could occur due to the outage of merchant transmission facilities, taking into account the financial transmission rights awarded to parties that have funded the new transmission facilities.
- Worked with the NYISO to develop a proposal for increasing the availability of long-term fixed price transmission congestion contracts.
- Worked with the IESO (Ontario) in the development and testing of an enhanced day-ahead unit commitment and associated financial settlements.
- Assisted a PJM market participant in a matter relating to FTR default.
- Working for a PJM market participant, coauthored a paper concerning competitive electricity market issues potentially arising from policies regarding transmission expansion and generation capacity markets; filed in FERC ANOPR proceeding.

- Worked with the California ISO in their stakeholder process to develop rules for the definition, allocation and auction of financial transmission rights, in support of their filing to implement LMP as part of their MRTU; filed supporting testimony 1/07.
- Coauthored a study (with Scott M. Harvey and Bruce McConihe) analyzing the benefits from the implementation of coordinated electricity markets in New York and PJM.
- Assisted the Midcontinent ISO in developing rules for allocating financial transmission rights, and all other market rules pertaining to financial transmission rights, in support of their LMP market system; worked intensively with their Transmission Rights Task Force.
- Worked with the NYISO to develop a process for awarding incremental financial transmission rights to parties that build new transmission.
- Served as a consultant to the NYISO in developing market rules to address revenue shortfalls that occur in the settlement of financial transmission rights when transmission lines are out of service, or for other reasons; assisted in testing methodology and with tariff filings.
- Advised Entergy and the SeTrans ISA Sponsors in developing rules for allocating financial transmission rights and awarding incremental financial transmission rights to parties that “participant fund” expansions to the transmission system, in support of an LMP market system.
- Advised the NYISO in analyzing the cause of a substantial congestion rent shortfall, and in addressing the settlement consequences of the shortfall.
- Prepared a paper for Mirant showing how a demand/supply imbalance in the West contributed to spikes in electricity prices from May 2000 to June 2001.
- Assisted several clients in determining how to perform the analyses required to provide financial transmission rights as options.
- Assisted the NYISO, ISO New England and Ontario IMO in assessing alternative approaches to creating a combined day-ahead electricity market for the Northeast.
- Worked with a large Midwestern utility to create a proposal for an independent transmission company that would operate a bid-based electricity spot market and use locational pricing.
- Advised the Northwest RTO on market-based systems for congestion management, the creation of an electricity spot market and the design and allocation of financial transmission rights.
- Assisted in testing the pricing software of the NYISO prior to startup.
- Assisted in developing methodologies for performing price verification for the NYISO’s LMP system.
- Assisted ISO New England in developing a congestion management system based on locational pricing and financial transmission rights.
- Led seminars on LMP and financial rights for many companies, such as Ontario Hydro.
- Participated in meetings with FERC economic staff to discuss issues such as participant funding of transmission expansion under LMP.
- Served as a consultant to the New York utilities in the development of plans and filings for restructuring the New York Power Pool as the New York Independent System Operator.
- Evaluated alternative models for pricing energy, transmission, capacity and ancillary services

within a competitive power market.

- Developed market-based energy, transmission and ancillary services pricing systems, including the two-settlement system, locational pricing and financial transmission rights.
- Participated in the development of regulatory filings and regulatory strategy for implementing electric industry restructuring and a competitive generation market.
- Developed systems for allocating financial transmission rights, including a multi-round auction, auction revenue rights, and the “business solution”.
- Assisted in developing alternative methods for transmission pricing.
- Participated in the development of the LMP system for the PJM interconnection.
- Assisted diverse parties, such as independent generators and marketers, in assessing restructured electricity markets in the U.S.
- Performed detailed analyses and built models of the impact of market and regulatory changes on the value of electric utility generation assets.
- Assisted with the development of models to forecast locational electricity prices.
- Evaluated the fit between restructured electricity markets and retail access programs.
- Estimated real and reactive locational marginal cost prices of power using linear programming models.
- Developed linear programming models to estimate ex post locational marginal cost electricity prices.
- Assessed market and regulatory risks confronting a consortium of energy utilities and analyzed the potential impact on their value and cost of capital.
- Developed testimony and analyses to assess regulatory policies requiring monetization of environmental externalities.
- Assessed the economic benefits of consolidating Massachusetts’s electric utilities.

Other Consulting

- Developed economic arguments and damages estimates for a case concerning alleged price discrimination in the wholesale gasoline market.
- Analyzed learning curves to support expert testimony concerning predatory behavior and patent infringement in the semiconductor industry.
- Estimated the market value of a closely held private company for a tax arbitration case.
- Assisted large multinational oil and gas clients in developing an economic foundation for cost allocation for an arbitration proceeding.
- Participated in evaluating the antitrust liability of a group of consumer product companies accused of price fixing.
- Developed data and economic arguments to support expert testimony concerning an allegation of tying of software products.

PUBLICATIONS

- “Beneficiaries-Pay Approach Best for Transmission Cost Allocation,” Natural Gas and Electricity, Vol. 28, #2, September 2011.
- “L’aumento del prezzo dell’elettricità in California: la realtà dei fatti,” Susan L. Pope, p. 109-139 in “Piu energia per tutti, Perché la concorrenza funziona,” Carlo Stagnaro and Margo M. Thorning, Istituto Bruno Leoni, 2005.
- “Transmission Capacity Reservations Implemented through a Spot Market with Transmission Congestion Contracts,” with William W. Hogan and Scott M. Harvey, Electricity Journal, Vol. 9, #9, November 1996.

WORKING PAPERS AND REPORTS

- Susan L. Pope and William W. Hogan, Martina Lindovska and Jason R.H. Mann, “Embracing Merchant Transmission Investment”, October 15, 2018, prepared for AQUIND Ltd.
- Susan L. Pope and Kevin Wellenius, “Challenges of Estimating Opportunity Costs of Energy-Limited Resources and Implications for Efficient Local Market Power Mitigation,” May 9, 2018, prepared for Powerex.
- Susan L. Pope and William W. Hogan, “Priorities for the Evolution of and Energy-Only Electricity Market Design in ERCOT,” prepared for NRG and Calpine, May 2017.
- Scott Harvey and Susan Pope, “LHV Impact Analysis,” Prepared for the NYISO, January 14, 2016.
- Susan L. Pope, “Price Formation in ISOs and RTOs: Principles and Improvements,” Electric Power Supply Association paper, Filed in Docket No. ER14-14-000, October 29, 2014.
- Scott M. Harvey, William W. Hogan and Susan L. Pope, “Evaluation of the New York Capacity Market”, Prepared for the NYISO, March 5, 2013.
- Scott M. Harvey and Susan L. Pope, “Evaluation of MVP Transmission Cost Allocation Design”, Prepared for the Midwest ISO, June 10, 2010.
- Michael Cadwalader, Paul Gribik, William Hogan and Susan Pope, “Extended LMP and Financial Transmission Rights,” June 9, 2010.
- Scott M. Harvey and Susan L. Pope, “Evaluation of Midwest ISO Injection/Withdrawal Transmission Cost Allocation Design,” Prepared for the Midwest ISO, March 5, 2010 (Updated April 15, 2010).
- Michael Cadwalader, Scott M. Harvey and Susan L. Pope, “Comments on the Evaluation of an Unconstrained Price Day-Ahead Market Compared to an Enhanced Day-Ahead Commitment Process,” Prepared for IESO, August 29, 2008.
- Scott M. Harvey, Bruce M. McConihe and Susan L. Pope, “Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges,” November 20, 2006 (Revised June 18, 2007).
- Paul R. Gribik, William W. Hogan and Susan L. Pope, “Market-Clearing Electricity Prices and Energy Uplift,” December 31, 2007.
- Scott M. Harvey and Susan L. Pope, “CRR Study 2 Report Addendum,” California Independent System Operator, September 30, 2005.
- Scott M. Harvey and Susan L. Pope, “CRR Study 2: Evaluation of Alternative CRR Allocation

Rules,” California Independent System Operator, August 24, 2005.

- Scott M. Harvey and Susan L. Pope, “Illustration of Issues Arising in CRR Allocation to LAPs,” California Independent System Operator, July 1, 2005.
- Scott M. Harvey, Susan L. Pope and William W. Hogan, “Comments on the California ISO MRTU LMP Market Design,” California Independent System Operator, February 23, 2005.
- Scott M. Harvey and Susan L. Pope, “MSWG Expansion TCC Approach, Revised,” NYISO Market Structures Working Group, November 15, 2001.
- Scott Harvey and Susan L. Pope, “TCC Awards for Transmission Expansion: Identification of Unresolved Issues in the Proposed MSWG Award Process,” NYISO Market Structures Working Group, November 15, 2001.
- Susan L. Pope, “California Electricity Price Spikes: An Update on the Facts,” December 9, 2002.
- Scott M. Harvey and Susan L. Pope, “Application of the Make-Whole Approach and Shortfall Reduction Procedure to the Day-Ahead Market and TCC Auction,” NYISO Market Structures Working Group, October 17, 2003.
- Scott M. Harvey and Susan L. Pope, “Pre-Scheduling: Forward Ramp and Transmission Reservations, Concept of Operation,” for NYISO, August 8, 2001.
- Scott M. Harvey, Susan L. Pope, John P. Buechler and Robert M. Thompson, “Feasibility Study for a Combined Day-Ahead Market in the Northeast,” May 4, 2001 (Draft Reports January 19, 2001 and April 20, 2001).
- Michael D. Cadwalader, Scott M. Harvey, William W. Hogan and Susan L. Pope, “Coordinating Congestion Relief Across Multiple Regions,” October 7, 1999.
- Scott M. Harvey, William W. Hogan, Susan L. Pope, Andrew P. Hartshorn and Kurt Zala, “Preliminary Report - Phase IV Market Trials,” October 8, 1999.
- Scott M. Harvey, William W. Hogan, Susan L. Pope, Andrew P. Hartshorn and Kurt Zala, “Report on Phase III Market Trials,” September 17, 1999.
- Michael D. Cadwalader, Scott M. Harvey, William W. Hogan and Susan L. Pope, “Market Coordination of Transmission Loading Relief Across Multiple Regions,” November 18, 1998.
- Michael D. Cadwalader, Scott M. Harvey, William W. Hogan and Susan L. Pope, “Reliability, Scheduling Markets and Electricity Pricing,” May 1998.
- Scott M. Harvey, William W. Hogan and Susan L. Pope, “Transmission Capacity Reservations Implemented Through a Spot Market with Transmission Congestion Contracts,” July 9, 1996 (revised versions, various dates).
- Scott M. Harvey, William W. Hogan and Susan L. Pope, “Transmission Capacity Reservations and Transmission Congestion Contracts,” June 1996 (revised versions, various dates).

CONFERENCES AND OTHER PUBLIC PRESENTATIONS

- Susan L. Pope, speaker at Energy Trading Institute Annual Conference, March 5, 2018, “RTO/ISO and Economist Perspective Panel”.

- Susan L. Pope, “Competitive Electricity Markets: Ontario’s Journey to LMP,” Consortium for Energy Policy Research at Harvard, December 19, 2018.
- Susan L. Pope, speaker at Energy Bar Association 2019 Mid-Year Energy Forum, October 29, 2018, session title: “New Tech, Aging Regs”.
- Susan L. Pope, “Market Power Mitigation in Ontario and Learnings from U.S. ISOs,” Annual Workshop on the Economics of Electricity Policy and Markets, IVEY Energy Policy and Management Centre, October 18, 2018.
- Susan L. Pope, Western Power Trading Forum NW Roundtable, October 5, 2018, panel discussion of CAISO proposal for default energy bids for market power mitigation.
- Co-Chair of Gulf Coast Power Association 33rd Annual Fall Conference, October 2-3, 2018, moderated panel: “Interactive Look at the Future Electric Industry”.
- William W. Hogan and Susan L. Pope, “Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT,” Infocast ERCOT Market Summit, February 28, 2018.
- Joe Cavicchi, Scott M. Harvey, and Susan Pope, “ERUC Fundamentals: Design Elements 9-13,” Prepared for Ontario IESO, Toronto, Ontario, November 27, 2017.
- Joe Cavicchi, Scott M. Harvey, and Susan Pope “ERUC Fundamentals: Design Elements 1-8,” Prepared for Ontario IESO, Toronto, Ontario, October 30, 2017.
- Joe Cavicchi, Scott M. Harvey and Susan Pope, “ERUC: Overviews and Design Elements,” Prepared for Ontario IESO, Toronto, Ontario, October 11, 2017.
- Scott M. Harvey and Susan Pope, “Single Schedule Market Pricing Issues, Phase 2 (Options) – Session 2, Load Pricing and Market Power Mitigation Options,” Prepared for Ontario IESO, Toronto, Ontario, August 17, 2017.
- Scott M. Harvey and Susan Pope, “Single Schedule Market Pricing Issues, Phase 2 – Session 2, Module G: Market Power Mitigation Options,” Prepared for Ontario IESO, Toronto, Ontario, August 17, 2017.
- Scott M. Harvey and Susan Pope, “Single Schedule Market Pricing Issues, Phase 2 – Session 1, Price Formation Options,” Prepared for IESO, Toronto, Ontario, July 27, 2017.
- Scott M. Harvey and Susan Pope, “Single Schedule Market Pricing Issues, Phase I – Session 3, Module H: Make Whole Payments and Uplift,” Prepared for IESO, Toronto, Ontario, July 27, 2017.
- Susan L. Pope, “Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT,” Gulf Coast Power Association, Austin, TX, July 12, 2017.
- Scott M. Harvey and Susan Pope, “Single Schedule Market Pricing Issues, Phase I – Session 3, Module G: Market Power Mitigation Appendix,” Prepared for IESO, Toronto, Ontario, June 29, 2017.
- Scott M. Harvey and Susan Pope, “Single Schedule Market Pricing Issues, Phase I – Session 3, Module G: Market Power Mitigation,” Prepared for IESO, Toronto, Ontario, June 29, 2017.
- Scott M. Harvey and Susan Pope, “Single Schedule Market Pricing Issues, Phase I – Session 3, Module F: Load Pricing,” Prepared for IESO, Toronto, Ontario, June 29, 2017.

- Scott M. Harvey and Susan Pope, "Single Schedule Market Pricing Issues, Phase I – Session 2, Module E: Pricing Operation Restrictions and Operator Actions," Prepared for IESO, Toronto, Ontario, June 2, 2017.
- Scott M. Harvey and Susan Pope, "Single Schedule Market Pricing Issues, Phase I – Session 2, Module D: Multi-Interval Optimization and Pricing," Prepared for IESO, Toronto, Ontario, June 2, 2017.
- Scott M. Harvey and Susan Pope, "Single Schedule Market Pricing Issues, Phase I – Session 2, Module C: Pricing Constraint Violations," Prepared for IESO, Toronto, Ontario, June 2, 2017.
- Scott M. Harvey and Susan Pope, "Single Schedule Market Pricing Issues, Phase I – Session 2, Module B: Reserve Pricing," Prepared for IESO, Toronto, Ontario, June 2, 2017.
- Scott M. Harvey and Susan Pope, "Single Schedule Market Pricing Issues, Phase I – Session 2, Module A: Energy Pricing," Prepared for IESO, Toronto, Ontario, June 2, 2017.
- Scott M. Harvey and Susan Pope, "Single Schedule Market Pricing Issues -- Introduction" Prepared for IESO, Toronto, Ontario, June 2, 2017.
- Scott M. Harvey and Susan Pope, "Single Schedule Market Pricing Issues Phase I Discussion," Prepared for Ontario IESO, Toronto, Ontario, May 4, 2017.
- Susan L. Pope, "Priorities for Improving Energy Price Formation in ERCOT," Gulf Coast Power Association 31st Annual Spring Conference, Houston, TX, April 20, 2017.
- Susan L. Pope, invited moderator for EUCI "Price Formation Issues in Wholesale Energy Markets" Conference, Baltimore, MD, April 10, 2017.
- Scott M. Harvey and Susan Pope, "Single Schedule Market Pricing Issues Phase I Discussion," Prepared for IESO, Toronto, Ontario, May 4, 2017.
- Susan L. Pope, "Update on Energy Price Formation," University of Texas Gas and Power Institute, September 8, 2016.
- Susan L. Pope, invited panelist for Skadden, Arps et al. Eleventh Annual Energy Conference, "Whither Electricity Markets," March 8, 2016.
- Susan L. Pope, invited panelist for FERC Technical Conference, Dockets Nos. EL16-6-001 and ER16-121-000, February 4, 2016 (addressing PJM's ARR and FTR allocations and settlements).
- Scott M. Harvey and Susan Pope, "G-J Impact Analysis," Prepared for New York ISO, Albany, NY, January 14, 2016.
- Susan L. Pope, moderated panel discussion, "Uplift and Price Formation in PJM," Infocast PJM Market Summit 2015, September 17, 2015.
- Susan L. Pope, UBS conference call speaker, "Delving into Scarcity Price Formation," October 31, 2014.
- Susan L. Pope, invited panelist for FERC Workshop, "Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators," Docket No. AD14-14-000, September 5, 2014.
- Susan L. Pope, "Electricity Industry Fundamentals," EUCI Conference, June 16, 2013.
- Scott M. Harvey, William H. Hogan, and Susan L. Pope, "Evaluation of the New York ISO Capacity

Market: Summary of Draft Report,” New York ISO ICAP Working Group, September 11, 2012.

- Scott M. Harvey, William H. Hogan, and Susan L. Pope, “Preliminary Evaluation of the New York ISO Capacity Market,” New York ISO ICAP Working Group, July 31, 2012.
- Scott M. Harvey and Susan L. Pope, “Funding Uneconomic Transmission Investments: Wind Energy in the Midwest ISO,” Rutgers Advanced Workshop in Regulation and Competition, June 25, 2010.
- Scott M. Harvey and Susan L. Pope, “Comments on MVP Transmission Cost Allocation Design,” Prepared for Midwest ISO, June 10, 2010.
- Scott M. Harvey and Susan L. Pope, “Final Report on Midwest ISO Injection/Withdrawal Transmission Cost Allocation Design,” March 10, 2010, Prepared for Midwest ISO RECB meeting, March 11, 2010.
- Scott M. Harvey and Susan L. Pope, “Defining and Implementing Transmission Maintenance Performance Incentives in LMP Markets,” Infocast Transmission Summit 2006, March 15, 2006.
- Scott M. Harvey, Bruce M. McConihe and Susan L. Pope, “Analysis of Impact of Coordinated Electricity Markets on Consumer Electricity Charges,” Center for Research in Regulated Industries, Rutgers University, 20th Annual Western Conference, Monterey, CA, November 20, 2006 (Revised June 18, 2007).
- Susan L. Pope, “FTRs: Status and Next Steps,” EUCI National Perspectives on Financial Transmission Rights, March 20, 2007.
- Scott M. Harvey and Susan L. Pope, “Defining and Implementing Transmission Maintenance Performance Incentives in LMP Markets,” Infocast Transmission Summit 2006, March 15, 2006.
- Susan L. Pope, “CRR Allocation Rules: Illustration of CAISO’s Proposed Treatment of Retail Access,” October 5, 2005.
- Scott M. Harvey and Susan L. Pope, “CRR Allocation Methodology Examples,” California Independent System Operator, August 31, 2005.
- Scott M. Harvey and Susan L. Pope, “Expanded CRR Study 2 Results,” California Independent System Operator, August 18, 2005.
- Susan L. Pope and Scott M. Harvey, “CRR Allocation Rules: CAISO Straw Proposal for LSEs,” California Independent System Operator, August 18, 2005.
- Susan L. Pope and Scott M. Harvey, “CRR Allocation Rules: Discussion of Eligible LSE CRR Sources,” California Independent System Operator, July 14, 2005.
- Scott M. Harvey and Susan L. Pope, “CRR Study 2 Metrics and CRR Allocation by Eastern and Midwestern ISOs,” California Independent System Operator, June 21, 2005.
- Susan L. Pope, “CRR Allocation Objectives: Stakeholder Discussion Paper,” California Independent System Operator, May 19, 2005.
- Scott M. Harvey, Susan L. Pope and William W. Hogan, “Comments on ISO MRTU LMP Market Design,” California Independent System Operator, March 2, 2005.
- Richard Doying and Susan L. Pope, “FTR Allocation Time Frame,” Midwest ISO Market Subcommittee, September 4, 2003.

- Richard Doying and Susan L. Pope, “FTR Definition for ‘Slice of System Sales,” Midwest ISO Market Subcommittee, September 4-5, 2003.
- Susan L. Pope and Richard Doying, “FTR Allocation, Nomination and Re-Nomination,” Prepared for the Midwest ISO Transmission Rights Task Force, September 4-5, 2003.
- Susan L. Pope and Richard Doying, “Market Subcommittee: FTR Allocation SFT Alternatives,” Revision 1, August 21, 2003, Prepared for the Midwest ISO Transmission Rights Task Force, August 21, 2003.
- Richard Doying and Susan L. Pope, “Adjustments to FTR Initial Allocation – Re-Nomination, Reflecting ‘Take-Backs’ from July 7th Meeting,” Prepared for the Midwest ISO Transmission Rights Task Force, August 22, 2003.
- Richard Doying and Susan L. Pope, “Adjustments to FTR Initial Allocation – Re-Nomination,” MISO Transmission Rights Task Force, July 18, 2003.
- Richard Doying and Susan L. Pope, “FTRs for Pumped Storage,” MISO Transmission Rights Task Force, April 17, 2003.
- Richard Doying and Susan L. Pope, “Treatment of Grandfathered Transmission Agreements in Transition to NYISO,” MISO Transmission Rights Task Force, April 17, 2003.
- Susan L. Pope and Richard Doying, “Opt-Out in the FTR Initial Allocation,” MISO Transmission Rights Task Force, March 21, 2003.
- Susan L. Pope, Arthur Desell and Greg Williams, “Management of Day-Ahead Congestion Rent Shortfall: Short List Topics,” NYISO Congestion Reduction Task Force, January 29, 2003.
- Susan L. Pope and Richard Doying, “Initial Allocation of FTRs – Examining the Alternatives,” MISO Transmission Rights Task Force, January 9-10, 2003
- Susan L. Pope and Richard Doying, “Initial Allocation of FTRs – Introductory Remarks,” MISO Transmission Rights Task Force,” January 9-10, 2003.
- Susan L. Pope and Richard Doying, “Pre-OATT Rights – Issues Impacting Initial FTR Allocation,” MISO Transmission Rights Task Force, January 9-10, 2003.
- Susan L. Pope and Carl Monroe, “Options, Obligations and Pro-Rationing – Treatment of Existing Entitlements in the Initial Allocation of FTRs,” MISO Transmission Rights Task Force, November 22, 2002.
- Susan L. Pope and Roberto Paliza, “Initial Allocation Methodology,” MISO Transmission Rights Task Force, October 18, 2002.
- Susan L. Pope, “FTRs, ARRs and Load Growth,” MISO Transmission Rights Task Force, October 18, 2002.
- Susan L. Pope and Roberto Paliza, “Market Design Issues,” MISO Transmission Rights Task Force, October 1, 2002.
- Susan L. Pope and Roberto Paliza, “Discussion of FTR Issues Raised by the SMD NOPR,” MISO Transmission Rights Task Force, August 30, 2002.
- Susan L. Pope, “LMP Congestion Money Flow and Transmission Rights Allocation,” MISO Transmission Rights Task Force, June 20, 2002.

- Arthur Desell (NYISO) and Susan L. Pope (LECG), “Congestion Reduction Task Force, Meeting I,” June 15, 2002.
- Susan L. Pope, “MISO Congestion Management System: Transmission Rights Task Force: Day-2 Transmission Rights Allocation Approaches,” MISO Transmission Rights Task Force, April 23, 2002.
- Susan L. Pope, “TCC Awards for Transmission Expansions,” PJM Regional Transmission Planning Stakeholder Process Meeting, April 12, 2002.
- Susan L. Pope, “TCC Awards for Transmission Expansions,” NYISO Business Issues Committee, March 20, 2002.
- Susan L. Pope and Scott M. Harvey, “TCC Awards for Transmission Expansions,” FERC Staff, March 11, 2002.
- Susan L. Pope, “MSWG Expansion TCC Award Process: Project Update II,” NYISO Market Structure Working Group,” February 12, 2002.
- Susan L. Pope and Scott M. Harvey, “MISO Congestion Management System: Financial Transmission Rights in MISO, Allocation Issues and Process,” MISO Transmission Rights Allocation Task Force, January 30, 2002.
- Susan L. Pope, “MSWG Expansion TCC Award Process: Project Update,” NYISO Market Structure Working Group,” January 15, 2002.
- Susan L. Pope and Scott M. Harvey, “LMP and Financial Rights Basics,” MISO Transmission Rights Task Force, Carmel, IN, January 10, 2002.
- Susan L. Pope and Scott M. Harvey, “Financial Transmission Rights in MISO – Overview of Allocation Process and Issues,” MISO Transmission Rights Task Force, Carmel, IN, January 10, 2002.
- Scott M. Harvey and Susan L. Pope, “TCC Expansion Awards for Controllable Devices: Initial Discussion,” NYISO Market Structures Working Group, November 16, 2001.
- Susan L. Pope and Scott M. Harvey, “MSWG Expansion TCC Award Process: Task 1: Resolution of Ambiguities,” NYISO Market Structures Working Group, November 16, 2001.
- Susan L. Pope and Scott M. Harvey, “MSWG Expansion TCC Award Process: Task 1: Modified Award Process,” NYISO Market Structures Working Group, November 16, 2001.
- Susan L. Pope, “TCC Auction Feasibility Test with Pre-Existing TCC Options,” NYISO Market Structures Working Group, November 16, 2001.
- Scott M. Harvey and Susan L. Pope, “MSWG Expansion TCC Approach, Revised,” NYISO Market Structures Working Group, November 15, 2001.
- Scott M. Harvey and Susan L. Pope, “TCC Awards for Transmission Expansion: Identification of Unresolved Issues in the Proposed MSWG Award Process,” NYISO Market Structures Working Group, November 15, 2001.
- Susan L. Pope, “An Empirical Assessment of the Success of Financial Rights Auctions in PJM and New York,” EUCI Electric Power Market Performance Conference, Denver, CO, September 20, 2001.

- Susan L. Pope, “Financial Rights Auctions in PJM and New York: Empirical Assessment,” EUCI Electric Power Market Performance Conference, Denver, CO, September 20, 2001.
- Susan L. Pope and John Chandley, “Overview of ITC Congestion Management Proposal,” Prepared for ITC/Alliance/MISO Meeting, March 24, 2000.
- Susan L. Pope, “LMP – Market-Based Real-Time Balancing and Congestion Management,” Midwest ISO Owner’s Committee, Midwest ISO Policy Subcommittee, March 15, 2000.
- Scott M. Harvey, William W. Hogan, Susan L. Pope, Andrew P. Hartshorn and Kurt Zala, “Review of Phase IV Market Trials,” Prepared for New York ISO – Market Participants Meeting, October 11, 1999.
- Scott M. Harvey, William W. Hogan, Susan L. Pope, Andrew P. Hartshorn and Kurt Zala, “Review of Phase III Market Trials,” Prepared for New York ISO – Market Participants Meeting, September 21, 1999.
- Scott M. Harvey, Susan L. Pope and Andrew P. Hartshorn, “Allocation of Financial Transmission Rights in California, New York and PJM,” NEPOOL Joint CMS/MSS Group, August 4, 1999.
- Scott M. Harvey, Susan L. Pope and Andrew P. Hartshorn, “Nodal-Zonal Pricing Part II – Zonal FCRs,” NEPOOL Joint CMS/MSS Group, August 4, 1999.
- Scott M. Harvey and Susan L. Pope, “A Nodal-Zonal Pricing System,” NEPOOL Joint CMS/MSS Group, July 19, 1999.
- Susan L. Pope, “Overcoming Transmission Constraints: Market-Based Approach to Congestion Management,” EPRM Power ’99 Conference, Houston, TX, June 23-24, 1999.
- Susan L. Pope, “Overview of Locational Pricing Principles,” Designing the Ideal ISO for Your Regional Energy Market, Infocast Conference, Washington, DC, May 28, 1999.
- Scott M. Harvey and Susan L. Pope, “Ancillary Services in a Two-Settlement System,” NEPOOL Joint CMS/MSS Group, May 27, 1999.
- Scott M. Harvey and Susan L. Pope, “Reliability Commitment and Scheduling Issues,” NEPOOL Joint CMS/MSS Group, May 27, 1999.
- Scott M. Harvey and Susan L. Pope, “Overview of the Straw Proposal,” NEPOOL Joint CMS/MSS Group, May 10, 1999.
- Scott M. Harvey and Susan L. Pope, “Market Hubs and Transaction Scheduling,” NEPOOL Joint CMS/MSS Group, May 10, 1999.
- Richard Dudeck (Williams), Charles A. King (NYISO), Scott M. Harvey and Susan L. Pope, “An Introduction to Independent System Operators and Electric Industry Restructuring,” 1999 SERC System Operator Conference, April 28-29, 1999.
- John Chandley and Susan L. Pope, “The Role of Financial Rights in Congestion Management: Price Certainty and Liquidity,” Megawatt Daily Transmission Issues Conference, March 24-25, 1999.
- Susan L. Pope, “Business Implications of Transmission Pricing: Why Congestion Matters,” ACI Electric Power Market Restructuring Conference, Washington, DC, February 18, 1999.
- Scott M. Harvey and Susan L. Pope, “Locational Pricing,” NEPOOL Regional Market Operations

Committee and NEPOOL Regional Transmission Operations Committee, Westborough, MA, September 25, 1998.

- Scott M. Harvey and Susan L. Pope, “Locational Pricing,” NEPOOL Regional Transmission Planning Committee, Westborough, MA, September 8, 1998.
- John D. Chandley and Susan L. Pope, “Overview on Transmission Pricing and Congestion: Possible Solutions,” Pasha Publications Conference on PJM Power, June 16, 1998.
- Susan L. Pope and Steve Henderson, “Understanding Transmission,” SERC Power Markets Conference, May 19, 1998.
- Scott M. Harvey, Susan L. Pope and Michael D. Cadwalader, “Understanding Transmission,” Pasha Publications/MW Daily, Ercot Power Markets Conference, March 31, 1998.
- “Transferring Transmission Rights – The Case for Financial Rights,” SLP, InfoCast Conference on Congestion Pricing & Tariffs, January 22-23, 1998.
- Susan L. Pope, “Hub-and-Spoke Transmission Congestion Contracts,” Presented to NYPSC Staff, May 22, 1997.
- Scott M. Harvey and Susan L. Pope, “The Impact of Alternative Electricity Market Structures on Stranded Generation Costs,” IBC Stranded Costs Conference, June 20, 1996.

TESTIMONY

- Susan L. Pope, Written Evidence, Alberta Utilities Commission Proceeding ID No. 23757 regarding the Alberta Electricity System Operator Comprehensive Market Design, February 28, 2019 (engaged by Industrial Power Consumers Association of Alberta and Alberta Direct Connect Consumer Association to provide objective evidence to the Alberta Utilities Commission).
- Susan L. Pope, Comments on Alberta Capacity Market Design, Alberta Utilities Commission Proceeding ID No. 23757 regarding the Alberta Electricity System Operator Comprehensive Market, November 2, 2018 (engaged by Industrial Power Consumers Association of Alberta and Alberta Direct Connect Consumer Association to provide objective evidence to the Alberta Utilities Commission).
- Susan L. Pope, prefiled testimony for The State of Texas Senate Committee on Business and Commerce, May 1, 2018 Hearing, Panel 3 (on behalf of NRG and Calpine).
- Susan L. Pope, Affidavit on Behalf of Elliott Bay Energy Trading, LLC (concerning ARR and FTR settlements and markets), FERC Docket Nos. ER16-121-000, EL16-6-000 and EL16-6-001, March 15, 2016.
- Susan L. Pope, Affidavit of Dr. Susan L. Pope on Behalf of MPS Merchant Services, Inc., FERC Docket Nos. EL00-95-280, EL00-95-271 and EL00-95-281, November 4, 2015 (concerning price effects alleged during CA electricity crisis).
- Susan L. Pope, Affidavit, Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, FERC Docket No. RM15-24-000, November 30, 2015 (on behalf of EPSA).
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**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

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Docket No. ER19-__-000

PJM Interconnection, L.L.C.

Docket No. EL19-__-000

VERIFICATION OF DR. WILLIAM W. HOGAN

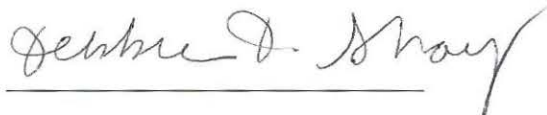
Dr. William W. Hogan, being first duly sworn, deposes and states that he is the Dr. William W. Hogan referred to in the foregoing document entitled "Affidavit of Drs. William W. Hogan and Susan L. Pope", that he has read the same and is familiar with the contents thereof, and that the testimony set forth 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 21st day of March, 2019.



DEBBIE D. SHAY
Notary Public
Commonwealth of Massachusetts
My Commission Expires
November 14, 2025



Notary Public



Attachment D

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-____-000
	)	
PJM Interconnection, L.L.C.	)	Docket No. EL19-____-000

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

A. Introduction

1. My name is Adam Keech. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I currently serve as the Executive Director, Market Operations for PJM Interconnection, L.L.C. (“PJM”). I am submitting this affidavit on behalf of PJM in support of its reserve market reforms in this proceeding.

B. Work Experience and Responsibilities

2. I have served in my current position since 2016 but have served as Director or Senior Director of Market Operations since 2013 where I had very similar responsibilities. The Market Operations Departments at PJM are responsible for technical design, implementation, and clearing of all PJM electricity markets and include the Day-ahead Market Operations Department, the Real-time Market Operations Department, the Market Simulation Department, the Capacity Market Operations Department, and the Interregional Market Operations Department. The responsibilities of these departments include the Day-ahead and Real-time Energy Markets, Day-ahead Scheduling Reserve Market, Regulation, Synchronized Reserve and Non-Synchronized Reserve Markets, Financial Transmission Rights and Reliability Pricing Model auctions, the Market Efficiency Process, and Market-to-Market coordination between PJM and the Midcontinent Independent System Operator, Inc., and between PJM and the New York Independent System Operator, as well as coordination with other Balancing Authority Areas.
3. In my capacity as Executive Director of the Market Operations Departments, I am directly responsible for the development of market rule changes through PJM’s stakeholder process, oversight of the technical implementation of rule changes, and ensuring that PJM’s market operations processes and market clearing results adhere to the requirements detailed in the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement among Load Serving Entities in the PJM Region, and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.. As Executive Director of the Market Operations Departments, my basic responsibility is to make sure that PJM’s markets are designed in a manner that leads to efficient, intuitive market outcomes that minimize the cost of procurement, meet system reliability needs, and incentivize market participants to act in a manner that promotes system reliability. Prior to assuming my leadership role in Market Operations, I served as Director of

Dispatch for PJM where I was responsible for real-time system operations in the control room and compliance with North American Electric Reliability Corporation (“NERC”) standards. Before that, I served as manager of PJM’s Real-time Market Operations Department for three years, where I was directly responsible for PJM’s real-time markets including the Real-time Energy Market and the Regulation, Synchronized Reserve and Non-Synchronized Reserve Markets in addition to the Real-time Security Constrained Economic Dispatch tool used by PJM’s system operators.

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

C. Adaptations from the Model Introduced in the Affidavit of Dr. William W. Hogan and Dr. Susan L. Pope to the PJM Proposal

5. The purpose of this portion of my affidavit is to identify areas where PJM has adapted the Operating Reserve Demand Curve (“ORDC”) model supported by the Affidavit of Dr. William W. Hogan and Dr. Susan L. Pope¹ (“Hogan & Pope”) to fit PJM’s particular implementation, explain the rationale behind those modifications, and articulate why the PJM proposal still meets the desired objectives that Hogan & Pope outline.

6. PJM’s proposal has four goals that pertain to the valuation and performance of its reserve products.

- Better operational performance when reserves are deployed.

The Tier 1 product that is in existence today provides an unacceptably low level of performance that results in additional uncertainty in the control room, and the need for manual intervention by system operators, due to the lack of confidence in the product.² The consolidation of the Tier 1 and Tier 2 products into one Synchronized Reserve product with one set of commitment, compensation, and performance rules will directly address this issue.

- A better reflection of the operational need for reserves.

The frequent and necessary intervention by system operators into the dispatch tools³ is a clear indicator that there are elements missing in the dispatch model that require the operator to take such actions. Uncertainty in the forecasts used to drive the dispatch

¹ Affidavit of Dr. William W. Hogan and Dr. Susan L. Pope on Behalf of PJM Interconnection, L.L.C. (“Hogan & Pope Aff.”) which adopts the analysis and all findings and conclusions contained in the report entitled “PJM Reserve Markets: Operating Reserve Demand Curve Enhancements” (Mar. 22, 2019), including the Appendix thereto, to provide support for PJM’s proposal to reform its ORDC. (“Hogan & Pope PJM ORDC Report”). The Hogan & Pope Affidavit is included as Attachment C to this filing.

² See Affidavit of Christopher Pilon on Behalf of PJM Interconnection, L.L.C. (“Pilon Aff.”). The Pilon Affidavit is included as Attachment E to this filing.

³ Pilon Aff. ¶ 16.

solution is not accounted for today and needs to be. This can be accomplished through PJM's proposed ORDCs.

- Better price performance in the reserve markets.

According to the 2018 State of the Market Report for PJM (Table 10-18),⁴ the reserve clearing price in PJM for Synchronized Reserves only accounts for about 53% of the cost of reserves. Stated differently, nearly half of the billing in this market occurs via an out-of-market, pay-as-bid, make whole payment. It is clear that the current model is not achieving the goals of a uniform clearing price market and not producing just and reasonable rates. The use of the ORDC with a downward-sloping tail will address some of the pricing issues that exist in the market today that are largely created by the nearly vertical demand curve. This is identical to the issue that the Variable Resource Requirement Curve addressed in the capacity market when PJM implemented the Reliability Pricing Model in 2007.

- Remove the inequity in the Synchronized Reserve Market regarding Tier 1 reserves.

Today's model does not compensate Tier 1 resources unless there is an event, and also does not obligate performance, however, PJM system operators rely on Tier 1 reserves just as much as they do Tier 2 reserves. When Tier 1 reserves respond during an event, they are compensated differently than Tier 2 resources for providing the same service. This difference in compensation is discriminatory and part of the reason Tier 1 resources perform poorly when deployed. Removing this inequity and aligning the reserve market design more closely with other Independent System Operator ("ISO")/Regional Transmission Organization ("RTO") models will eliminate this issue.

1. The ORDC -- PJM's Proposed \$2,000/MWh Reserve Penalty Factor

7. A central finding in the Hogan and Pope PJM ORDC Report is that:

Implementation of the existing [PJM] design, especially given changing operating conditions, yields energy and operating reserve prices in PJM that do not align with economic principles. The prices of incremental reserves and energy can deviate from incremental cost and are not consistent with the implications of first principles for determining the value of operating reserves when supply is constrained. These inconsistencies with economic principles support the conclusion that the existing system for operating reserves and their associated pricing is not just and reasonable.⁵

⁴ Monitoring Analytics, LLC, *State of the Market Report for PJM* (Mar. 14, 2019), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf.

⁵ Hogan & Pope PJM ORDC Report at 3.

As such, a critical component of the Hogan & Pope model is the implementation of the ORDC. As explained by Hogan & Pope, ORDCs are administratively determined curves that are intended to reflect the willingness to pay for reserves.⁶ In the ORDC's application in the electricity market, the curve defines the willingness to exchange reserve for energy and acts as a cap on the reserve market clearing prices ("MCPs"). As illustrated in Figure 2 of the Hogan & Pope PJM ORDC Report, the ORDC takes a shape that begins at the value of lost load ("VOLL") minus the marginal cost of energy, and then gradually drops towards the x-axis in a manner that resembles an exponentially decaying function. The highest price point on the ORDC is the first area where the PJM proposal is adapted for the PJM-specific implementation of this model. In other words, rather than an ORDC cap representing VOLL, PJM's proposed cap is a \$2,000/MWh Reserve Penalty Factor, as explained below.

8. The Hogan & Pope model guarantees that prices do not exceed the VOLL. To accomplish this, the model begins with an assumed VOLL and the ORDC is derived from that. To ensure that prices never exceed the VOLL, the ORDC must be constructed by setting the highest price point at the VOLL minus the marginal cost of energy. This is required because in the co-optimization context, the determination of the cost of the next megawatt ("MW") of energy, the Locational Marginal Pricing ("LMP"), requires the re-dispatch of generation that can cause a depletion in the amount of available reserves. When the LMP is calculated, the cost to serve the next MW of energy is the sum of the marginal cost of energy plus the lost benefit to the load of maintaining a specific level of reserves. This lost benefit is determined on the margin as the price point on the demand curve associated with the megawatt of reserves that was lost by converting it to energy. To ensure that prices do not exceed the VOLL when the system operator is at the point where load will be shed to maintain reserves, the marginal cost of energy must be subtracted from the highest price point on the ORDC. This guarantees that the VOLL will not be violated.
9. PJM's implementation of the ORDC does not directly focus on the VOLL as a price cap despite the fact that the maximum prices under the PJM model fall into a reasonable range of estimates of the VOLL. While designing its ORDC model, PJM focused on the fact that a capacity market exists in PJM and that it has a role in ensuring resources needed to meet the "1-in-10" Loss of Load Expectation criteria are available. As stated in the introduction to this section, one of PJM's goals is to achieve better pricing of reserves, not to replace the role of the capacity market. Therefore, as PJM developed its model, PJM's primary focus was setting the highest point on its ORDCs, the Reserve Penalty Factors, at 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. This price is \$2,000/MWh.
10. The \$2,000/MWh Reserve Penalty Factor is directly tied to the fact that PJM's system operators may take actions to maintain reserves⁷ at any given time that can have an

⁶ Hogan & Pope PJM ORDC Report at 12-15.

⁷ PJM, *Manual 13: Emergency Operations*, § 2 (rev. 68, Jan. 1, 2019), <https://www.pjm.com/~media/documents/manuals/m13.ashx>

incremental offer that reaches the \$2,000/MWh price-setting cap that the Federal Energy Regulatory Commission (“FERC”) established in Order No. 831.⁸ While this scenario is not likely, it can happen and system operators are required to take actions in this price range to maintain reserves. When supply with high incremental offers, say \$2,000/MWh, are dispatched and set the LMP, the opportunity costs for resources dispatched down for reserves can be significant, up to \$2,000/MWh, if the reserve resource’s incremental offer is at or near \$0.00/MWh. To ensure these resources’ capability are fully utilized by PJM’s dispatch system and the prices reflect their utilization, the Reserve Penalty Factor 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. Today, that tradeoff occurs at the \$850/MWh Reserve Penalty Factor which is inconsistent with how the system is operated. This results in suppressed reserve and energy prices and uplift that could be prevented with a more complete model.

11. For example, consider a scenario where supply with a high incremental offer of \$1,800 has been dispatched to meet the demand for energy and reserves. This offer is marginal for energy and sets the LMP at its offer of \$1,800/MWh. Assuming no congestion or losses, it follows that all resources eligible to be re-dispatched down to provide reserves will incur a lost opportunity cost on the margin of the \$1,800/MWh LMP minus their offer. This lost opportunity cost reflects the revenues in the energy market that the resource owner will forego by following PJM’s instruction to provide reserves instead of collecting the \$1,800/MWh LMP. The resource’s cost is subtracted from the LMP to determine the lost opportunity cost because in order to collect the LMP (i.e., by generating electricity), the resource would have to incur the cost to generate such electricity. In this example, a resource with an offer of \$1,200/MWh would have a \$600/MWh lost opportunity cost. Because the current Reserve Penalty Factor (willingness to pay to maintain this product) is \$850/MWh and the cost for this resource to provide reserves is less than it, this resource would be assigned reserves and eligible to set the reserve market clearing price. However, if this resource’s offer was \$500/MWh, its opportunity cost would be \$1,300/MWh. This is higher than the current Reserve Penalty Factor and therefore this resource would not be re-dispatched for reserves by PJM’s Security Constrained Economic Dispatch (“SCED”) software and not assigned reserves. There are two possible outcomes from this: (1) system operators manually assign this unit reserves, reserve and energy prices do not reflect actual system conditions, and it is paid through uplift; or (2) there is an economic shortage because the physical capacity was available to meet the requirement but the willingness to pay for reserves (Reserve Penalty Factor) was set too low. Both are undesirable and reflect the need to increase the Reserve Penalty Factor.
12. While PJM does not have generation offers that meet this level every day, offers for emergency and pre-emergency demand response reach \$1,849/MWh every day. Additionally, emergency energy can be purchased from neighboring areas if needed with a cost exceeding \$2,000/MWh. PJM system operators will take these emergency actions

⁸ *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (2016), *order on reh’g & clarification*, Order No. 831-A, 161 FERC ¶ 61,156 (2017), *amended by* 165 FERC ¶ 61,136 (2018) (“Order No. 831”).

any time they are needed to maintain Primary and/or Synchronized Reserves. Even though the probability of needing to take these actions on any given day is low and decreases with increasing levels of reserves, it is nonetheless present every day and therefore establishes the lowest maximum willingness to pay for reserves at \$2,000/MWh.

13. PJM believes there are other beneficial properties to implementing Reserve Penalty Factors that are fixed at \$2,000/MWh to derive its ORDCs, rather than the dynamically calculated maximum level proposed by Hogan & Pope. They include:

- a. Simplicity.

An objective of PJM's proposal is to ensure PJM can feasibly implement the market design without a full redesign of its technical software. The Hogan & Pope model requires a continuous re-estimation of the marginal cost of energy so that the demand curve can be recalculated periodically. This continuous re-estimation, while theoretically sound, has not been implemented and would require a comprehensive redesign of PJM's dispatch and pricing software. An accurate estimate of the marginal cost of energy is essential to the Hogan & Pope model; however, producing an estimate that is accurate enough for use in the market clearing will require multiple iterations of the technical software which will increase solution time. PJM's proposal achieves the objectives through a solution that is technically feasible with minor enhancements to existing software.

- b. Transparency.

The fixed ORDCs proposed by PJM can be posted in advance to the market as they are not reliant on the dynamic estimate of the marginal cost of energy. This provides increased transparency and consistency to the market.

- c. Removal of potential skewing due to a poor estimation of the marginal cost of energy.

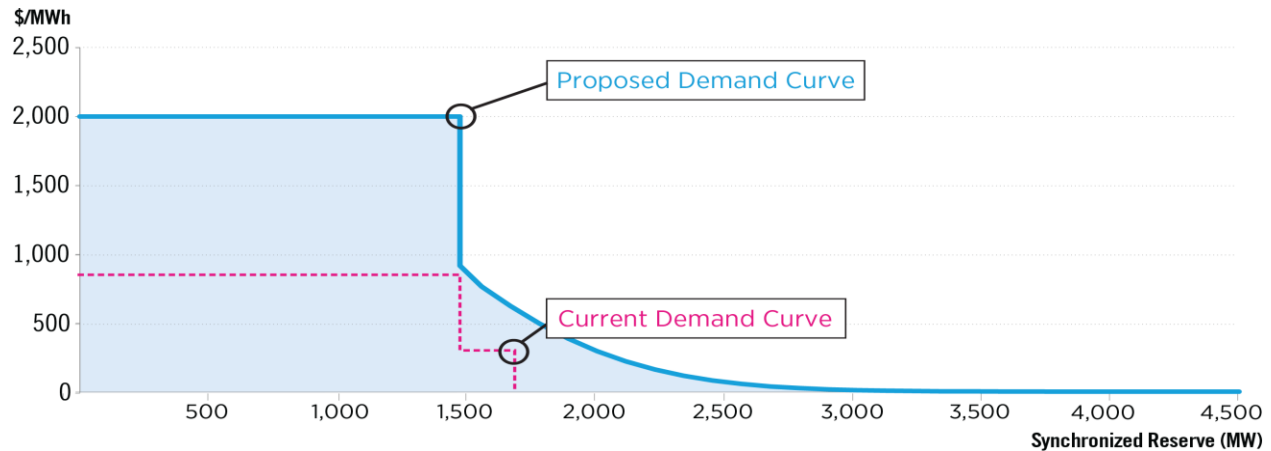
As stated previously, the Hogan & Pope model requires a periodic re-estimation of the marginal cost of energy to re-derive the ORDC as frequently as desired. If desired, this could occur in each dispatch solution, each hour, etc. Because the shape and level of the ORDC will ultimately impact the final marginal cost of energy, the marginal cost of energy that is used to compute the ORDC is only an estimate that is subject to error. Errors in the determination of this value can skew the market in one direction or another inappropriately. If the estimated marginal cost of energy is too high, the ORDC may undervalue reserves and lead to lower prices. If it is estimated too low, the opposite can occur. To remove this potential skewing, PJM proposed to use a fixed Penalty Factor of \$2,000/MWh.

2. *The Horizontal Section of the PJM ORDC*

14. As shown in Figure 1 below, PJM's proposed curve is characterized by a step function that eventually turns into a downward-sloping curve. From a cursory view, this curve appears inconsistent with the Hogan & Pope model given the ORDC illustrated in Figure

2 of the Hogan & Pope PJM ORDC Report. However, a curve of this shape is entirely consistent with their proposed model when taking into consideration the Minimum Reserve Requirement (“MRR”) PJM must employ to be consistent with NERC standards. See Hogan & Pope PJM ORDC Report at 35 (Figure 5).

Figure 1. Stylized Depiction of PJM-Proposed ORDC.



15. In the context described by Hogan & Pope, the security minimum reflects the level of remaining reserves at which the system operator will begin to shed load to preserve reliability. It is therefore consistent that when the security minimum is violated, prices are set to the VOLL as illustrated by the curve in Figure 5. In the PJM implementation, the security minimum is the MRR. This is not the point at which PJM will begin shedding load; rather, it is the point at which PJM will no longer be able to meet its minimum requirement of a specific reserve type. Because PJM is not shedding load at this point, the price on the ORDC for violating the MRR is not the VOLL, it is the maximum willingness to pay to maintain that reserve product. As I have explained previously, this level is \$2,000/MWh.
16. The Hogan & Pope model and the PJM proposal apply identical concepts around different operating points and prices. In the Hogan & Pope model, the horizontal portion of the curve is based on a security minimum requirement that must be maintained to avoid load shed and therefore when it is violated, the prices are set at the VOLL. In PJM implementation, the MRR sets the width of the horizontal step and the price is set at the maximum willingness to pay to maintain that level of reserves given the \$2,000/MWh cap on offers that are eligible to set prices.

3. PJM’s Locational Reserve Requirement Implementation

17. As discussed in the Hogan & Pope PJM ORDC Report, the model Hogan & Pope propose for the implementation of locational ORDCs includes an ORDC for the “Zone,” an ORDC for the “Rest of System” that does not include the “Zone,” and an ORDC for the closed-loop interface that limits reserve imports from the “Rest of System” into the

“Zone.” In this model, as shown in Figure 10 of the report and explained in more detail therein, the security minimum and net load error (uncertainty) used to determine the ORDC for the “Rest of System” does not include the security minimum and net load error in the “Zone.” Therefore, in this model, the “Zone” ORDC is independent from the “Rest of System,” ORDC; however, there is an interaction between these two regions through the closed-loop interface and its associated ORDC that connects them.

18. The main difference between the PJM proposed model and the Hogan & Pope model is that in the PJM proposed model, the ORDC for the sub-zone is contained within the ORDC for the RTO and therefore not established independently as in the Hogan & Pope model. Because of this relationship in the PJM proposed model, it follows that each megawatt of reserves in the sub-zone can meet the requirement in the sub-zone and the RTO simultaneously. This results in the clearing prices for reserves in the PJM model being calculated as the sum of the shadow prices for the applicable reserve requirement constraints in the sub-zone and the RTO. The Hogan & Pope model is different because the demand for reserves in the “Zone” and the “Rest of System” are independent. This leads to a different set of demand curves as explained above and a different interaction in the prices.
19. For example, in the PJM model, it is assumed that reserves that are assigned in the sub-zone are always available to meet the requirement in the sub-zone and the requirement in the RTO, simultaneously. However, in the Hogan & Pope model, there is a non-zero probability that the reserves in the sub-zone are needed in the sub-zone and the non-sub-zone portion of the RTO simultaneously but for different reasons. This could occur if there are simultaneously large, but independent, net load errors in the RTO and sub-zone, a large net load error in the RTO and a unit loss in the sub-zone, etc. As a result, the Hogan & Pope model more completely models all of the potential needs for locational reserves and will generally produce higher reserve prices under similar conditions than the PJM model because it captures this interaction that the PJM model does not.
20. Despite simplification of the PJM model, the PJM model has other beneficial aspects to it that make it a robust model for locationally valuing reserves.
 - a. Simplicity.

Like the estimate required of the marginal cost of energy to implement the ORDC proposed by Hogan & Pope, the implementation of their locational reserve model also requires estimates of certain variables to determine the “Zone,” “Rest of System,” and interface ORDCs. Producing accurate estimates for these variables will require multiple iterations of the model that could result in unacceptably high solution times. The model proposed by PJM is already in use in PJM’s market clearing systems. It has the benefit of having known impacts on market outcomes, can be solved in a reasonable amount of time, and is suitable for implementation in the real-time dispatch software.

b. Transparency.

As in the determination of the maximum price on the ORDC, the Hogan & Pope model requires an advanced estimate of reserves available in the “Zone,” the reserves available in the “Rest of System,” and the reserves being transferred over the interface. The PJM model does not require this estimation, because the regions are modeled as nested and therefore all reserves within the sub-zone can meet the requirement of the RTO. This results in curves that are not dynamically recalculated based on estimates and can be posted far in advance of the market clearing. This provides transparency to the market participants on the demand for reserves.

c. Removal of potential skewing due to poor estimates.

The estimates required to implement the Hogan & Pope model could ultimately skew market solutions in one direction or another depending on the direction of error in the estimate. In order to remove this potential skewing from the model, PJM is proposing continuing to use the nested model that is in place today.

4. Reserve Product Modeling

21. The difference between PJM and the Hogan & Pope approach regarding reserve product modeling is that the PJM model is nested whereas the Hogan & Pope model is not nested. Figure 4 of the Hogan & Pope PJM ORDC Report illustrates the PJM implementation. This model is characterized by reserve products that are completely nested within each other. For example, each megawatt of Synchronized Reserves is also a megawatt of Primary Reserves; every megawatt of Primary Reserves is also a megawatt of 30-minute Reserves. This model has been in place in PJM since the implementation of the Non-Synchronized Reserve Market in 2012. This model has also been implemented in other FERC-jurisdictional ISO/RTOs.
22. The nesting of these requirements results in product-level clearing prices that are the sum of the shadow prices associated with the requirement constraints that each product can meet (in other words, the market clearing prices are based on a “cascading” model). For example, the clearing price for Synchronized Reserves is the sum of the shadow prices of meeting the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement. This cascading ensures that prices are set consistently with the value of each product such that Synchronized Reserves always has a price greater than or equal to Non-Synchronized Reserves, and Non-Synchronized Reserves always has a price greater than or equal to 30-minute Reserves.
23. The Hogan & Pope model achieves the same pricing properties slightly differently because in their model, the ORDCs as input into the co-optimization of energy and reserves are not nested. Instead, the ORDCs are derived based on cascaded prices prior to being input into the co-optimization of energy and reserves. This requires estimates made on the amount of product X when deriving the ORDC for product Y to capture the impact that the quantity of product X has on the market clearing price paid to product Y. For example, an estimate on the amount of Non-Synchronized Reserves is required to

derive the Synchronized Reserve Requirement ORDC, because Synchronized Reserve resources are compensated for contributing to meet the Synchronized Reserve Requirement as well as the Primary Reserve Requirement (and the price associated with the latter requirement is impacted by the amount of Non-Synchronized Reserves). Due to the use of cascaded prices in the derivation of the ORDCs, the resulting shadow prices in the Hogan & Pope model are the reserve market clearing prices.

24. As in other areas of adaptation from the Hogan & Pope model, PJM believes its model reduces design and implementation complexity and removes the ability for inaccurate estimates used to derive the ORDCs to skew the market results.

5. Pricing Emergency Actions

25. Figure 6 of the Hogan & Pope PJM ORDC Report illustrates a concept of having multiple steps on the ORDC to represent different and potentially more severe emergency procedures prior to ultimately shedding load. The idea behind this proposal is that as emergency actions become more and more severe and progress towards load shed, prices should escalate consistently with the costs of those emergency actions. PJM agrees with this principle, however, it is proposing a different model intended to meet the same principle.
26. In the current PJM market design, certain types of emergency capacity submit offers/bids into the market. These include emergency segments on generation resources, pre-emergency and emergency demand response, and offers to sell emergency energy. In all of these cases, these submitted offers are eligible to set the LMP up to the \$2,000/MWh offer cap established by FERC Order No. 831.⁹ Additionally, PJM calculates LMPs and reserve market clearing prices consistent with a reserve shortage of all products in any location where a Voltage Reduction Action and/or a Manual Load Dump Action are in effect.¹⁰ The purpose of this rule is two-fold: (1) it ensures that prices are appropriately escalated when severe emergency procedures are in effect; and (2) it ensures that the capacity made available following a reduction in the load due to a Voltage Reduction Action or a Manual Load Dump Action does not suppress the market clearing prices. Absent this set of provisions, PJM could enter a Manual Load Dump Action, reduce system load involuntarily, and prices could fall. This is an unacceptable market outcome as it mutes any incentive for efficient deployment of energy and reserves.
27. The Hogan & Pope model proposes an alternative which is to set discrete price points on the ORDCs for each emergency action preceding load shed. For PJM, this emergency action would be the Voltage Reduction Action. While PJM agrees with this concept, it is difficult to determine a reasonable, supportable, price associated with this specific action.

⁹ Emergency energy may be purchased from neighboring regions at offers levels that are uncapped. These transactions are presently capped at \$2,700/MWh for price-setting purposes and PJM proposes to further modify that cap to \$2,000/MWh as part of this filing.

¹⁰ PJM, *Manual 11: Energy & Ancillary Services Market Operations*, § 2.8 (rev. 104, Feb. 7, 2019), <https://www.pjm.com/~media/documents/manuals/m11.ashx>.

Hogan & Pope note this difficulty as well.¹¹ Additionally, given the cascading model that PJM plans to implement, setting market clearing prices consistent with a reserve shortage of all products in the area that the load shed is effective will result in reserve and energy prices that exceed \$6,000/MWh under the PJM proposal, *a minimum level that is consistent with* a jointly optimized energy and reserve market clearing results. While this price would raise the energy price closer to the range of VOLL estimates, it may still fall below the true VOLL that reflects the hard-to-estimate value of reliability for a system as large and as complex as the PJM system. As a general matter, PJM believes that prices at this level (and higher) can be justified as consistent with the value of reliability for additional reserves across the PJM system reflected in its operational practice.

D. Simulation of Estimated Impact of the PJM Proposal

1. Simulation Background

28. To estimate the impact of the proposed changes, PJM performed simulations for the period of January 1, 2018 through December 31, 2018. These simulations were performed using software adapted from the Perfect Dispatch¹² platform to be able to model the PJM real-time market under the current and proposed reserve market design. The simulation software utilizes the actual offer data used in the real-time market as submitted by market participants and the actual real-time operating conditions including load, interchange, etc.
29. PJM did not directly attempt to simulate the day-ahead market. The day-ahead market results are significantly influenced by virtual transactions including Incremental Offers, Decremental Bids, and Up-to Congestion Transactions (i.e., “Virtual Transactions”) used to arbitrage differences between day-ahead and real-time. Simulating the day-ahead market under a new set of rules and a new set of real-time conditions with Virtual Transaction bid/offers that were submitted based on the initial market outcomes would not provide an outcome that PJM believes would reasonably represent the impacts of the proposal. However, in some simulations, as explained further herein, PJM did re-solve unit commitment as part of the real-time market simulation. This was done to recognize that including a more accurate reflection of reserve demand in the day-ahead market will have a beneficial effect on the unit commitment because all reserve products and demand will be considered, whereas they are not today.
30. Throughout the discussion below, I refer to “removing” or “eliminating” the Tier 1 reserve product. To be clear, when I use these terms I am referring to the removal of the ability for partially loaded generation resources to not be paid the clearing price, and only have a voluntary requirement to respond to reserve deployments with no consequence,

¹¹ Hogan & Pope PJM ORDC Report at 20-21.

¹² The Perfect Dispatch software is used by PJM for after-the-fact operational analysis. The tool uses the real-time operational information along with actual participant bid data and can simulate an operating day under various conditions. PJM adapted the software to model the proposed market rules in this filing and so that an entire year could run at a time as opposed to a single day.

despite PJM estimating a reserve amount for such resources. PJM still plans to utilize partially loaded generation resources for reserves but those reserves will be assigned, paid the clearing price, obligated to respond when deployed, and penalized for non-compliance.

2. *Simulation Methodology - Simulation Case for Estimating Cost Impacts of Removing Tier 1 – Case A*

31. To determine a market solution that includes the removal of the Tier 1 product, PJM utilized its simulation software and re-ran the real-time market for 2018. The configuration for this model is intended to reflect the current market design with several changes:
- The Tier 1 product is removed to determine its effect on Synchronized Reserve costs.
 - The simulation was performed without modeling the Mid-Atlantic and Dominion (“MAD”) sub-zone. This was another simplification added to the model. Based on the actual market results in 2018, the MAD sub-zone bound and resulted in higher reserve prices than in the RTO in only approximately 2% of all hours.
32. Additionally, in Case A, PJM did not fully optimize the unit commitment. The unit commitment from the day-ahead market as it existed on each day was taken as given and then only combustion turbine (“CT”) and diesel resources had their commitments optimized in the simulation. This is similar to PJM’s current operating practices in the real-time market and provides the best reflection of current market conditions. The commitment (on/off state) of all other resources was treated as fixed, although online resources were subject to re-dispatch in the simulation. The proposed changes to the ORDC and to the alignment of reserve products in the day-ahead and real-time markets were not included in this simulation in order to isolate the impact of the removal of Tier 1 in the real-time Synchronized Reserve market.

3. *Simulation Results*

a. *Tier 1 Removal - \$1.0 million*

33. Tier 1 resources are compensated in two different ways:
- They are paid a \$50.00/MWh premium in addition to the LMP for the MWhs they increase their output during a Synchronized Reserve Event;¹³ and,
 - They are paid the Synchronized Reserve Market Clearing Price (“SRMCP”) when the Non-Synchronized Reserve Market Clearing Price (“NSRMCP”) is greater than \$0.00/MWh.¹⁴
34. Specifically, with respect to Tier 1, PJM paid approximately \$1.4 million in payments to Tier 1 resources resulting from the \$50.00/MWh Tier 1 premium payment. In addition to that, Tier 1 resources were also compensated approximately \$4.7 million dollars for their estimated reserves when the NSRMCP was greater than \$0.00/MWh. Thus, to determine the impact of removing Tier 1, first PJM considers that there will be a \$6.1 million savings to load. But that is not the end of the story because one has to also consider how much PJM will pay for the now combined single Synchronized Reserve product.
35. To estimate the cost increase of removing Tier 1, PJM calculated the Synchronized Reserve Market revenues from Case A from the set of simulations provided in Table 1 and subtracted the actual Synchronized Reserve Market results from 2018 from them.

¹³ This compensation rule dates back to the implementation of the Synchronized Reserve Market in 2002 and was provided as an incentive for response during an event. The second component was implemented in 2012 coincident with PJM’s implementation of Shortage Pricing in compliance with Order No. 719. See *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057 (2012).

¹⁴ The rule to pay Tier 1 resources the SRMCP when the NSRMCP is greater than \$0.00/MWh was meant to ensure that Synchronized Reserves, including Tier 1, were always paid a price greater than or equal to that paid to Non-Synchronized Reserves. Absent this rule, there would exist scenarios when PJM is relying on Tier 1 reserves to meet its Synchronized Reserve Requirement yet paying Non-Synchronized Reserves, a lower quality product, a higher price. Thus, this rule was implemented to fix this undesirable consequence of the Tier 1 design.

Table 1. Base Case Simulation with Tier 1 Removed

Variable	Case A
	Current Market Rules with Tier 1 Removed (Partial Unit Commitment)
Load Weighted LMP (\$/MWh)	35.80
Weighted Synchronized Reserve MCP (\$/MWh)	1.99
Weighted Non-Synchronized Reserve MCP (\$/MWh)	1.03
Hourly Average Cleared Synchronized Reserve (MW/hour)	1,818
Hourly Average Cleared Non-Synchronized Reserve (MW/hour)	634
Hourly Average Cleared Total Reserve (MW/hour)	2,452
Total Cleared Synchronized Reserve (millions MWh)	15.5
Total Cleared Non-Synchronized Reserve (millions MWh)	5.4
Reserve Revenue (\$M)	36.4

36. Based on this simulation, the estimated payments of clearing price credits to resources assigned Tier 2 reserves and Non-Synchronized Reserves is \$36.4 million. Of that \$36.4 million, approximately \$30.8 million¹⁵ was paid to resources assigned Tier 2 through the clearing price. The balance of \$5.6 million was paid to resources that received Non-Synchronized Reserve assignments. The actual synchronized market results for 2018 are shown in Table 2. The \$30.8 million in synchronized reserve clearing price credits from the simulation represents an increase of approximately \$7.1 million from the \$23.7 million in credits from the actual market results reported in Table 2.

Table 2. 2018 Tier 2 Synchronized Reserve Revenues - Actual

2018 Tier 2 Synchronized Reserve Revenues – Actual	\$M
Clearing Price Credits	23.7
Synchronized Reserve Uplift	20.3
Total	44.0

37. PJM expects that the additional clearing price credits in the Synchronized Reserve Market will result in a reduction of uplift in this market as well, although that value was not estimated. PJM did not perform this calculation because the make-whole payment calculation done by Perfect Dispatch is performed simultaneously across all markets as opposed to the market-specific calculation done in PJM. PJM does not anticipate this reduction to be significant and therefore is assuming it is zero for the purpose of this

¹⁵ \$30.8 million is calculated as follows: Weighted Synchronized MCP (\$1.99/MWh) X Total Cleared Synchronized Reserves (15.5 million MWh).

analysis. Notwithstanding the reduction in Synchronized Reserve uplift payments, the net cost increase of removing the Tier 1 reserve product is the \$7.1 million increase in clearing price credits, minus the cost savings to loads from the removal of Tier 1 compensation of \$6.1 million. This results in an estimated net cost increase of \$1.0 million.

b. All Other Proposed Changes Combined – \$555 Million

38. Case A solely illustrates the impact of removing Tier 1 from the real-time Synchronized Reserve market. To estimate the cost impact of the total PJM package, PJM again used the same simulation software but updated the model to reflect the proposed market rules in totality. In addition to augmenting the market rules, PJM also re-executed the full unit commitment problem again. This is different than what was done in the assessment for the cost of the Tier 1 estimation where only CT and diesel resources had their commitments optimized. The purpose of re-solving the full unit commitment problem in this context is that it provides the best ability to simulate the benefits to the market of aligning the day-ahead and real-time reserves models. However, because the simulation software can only utilize actual real-time operational data from the period in question and not day-ahead market data, the unit commitment is re-solved based on known operating conditions, not the market participants' day-ahead expectations of real-time conditions with the new ORDCs implemented. This is an important distinction because optimizing the unit commitment for a known set of operating conditions removes all uncertainty and unnecessary commitments that may have otherwise been made due to forecast errors in day-ahead market bids and offers. These differences, therefore, need to be controlled for before a meaningful comparison can be made between the results of the proposed market rules and the current market rules using this simulation methodology.
39. To remove the impact of re-solving the unit commitment based on known conditions from the eventual assessment of the impacts of the proposed market rules, PJM first re-ran Case A without changing the ORDCs but re-solved the full unit commitment. This mimics clearing the day-ahead market with knowledge of the actual real-time operational data. The results are contained in Case B in Table 3 below.

Table 3. Market Impacts of Full Versus Partial Unit Commitment

Variable	Case A	Case B
	Current Market Rules with Tier 1 Removed (Partial Unit Commitment)	(Case A with Full Unit Commitment)
Load Weighted LMP (\$/MWh)	35.80	37.30
Generator Energy Revenue (\$M)	26,801	27,946
Weighted Synchronized Reserve MCP (\$/MWh)	1.99	2.58
Weighted Non-Synchronized Reserve MCP (\$/MWh)	1.03	1.26
Weighted Secondary Reserve MCP (\$/MWh)	N/A	N/A
Hourly Average Cleared Synchronized Reserve (MW/hour)	1,818	1,818
Hourly Average Cleared Non-Synchronized Reserve (MW/hour)	634	634
Hourly Average Cleared Secondary Reserves (MW/hour)	N/A	N/A
Hourly Average Cleared Total Reserve (MW/hour)	2,452	2,452
Total Cleared Synchronized Reserve (millions MWh)	15.5	15.5
Total Cleared Non-Synchronized Reserve (millions MWh)	5.4	5.4
Total Cleared Secondary Reserve (millions MWh)	N/A	N/A
Reserve Revenue (\$M)	36.4	46.8
Uplift (\$M) ¹⁶	109.9	30.4
Bid Production Cost (\$M)	13,230	13,121
Total Energy and Reserve Market Revenues (\$M)	26,838	27,993

40. The differences between Case A and Case B are significant. The Load Weighted LMP for the year increases by \$1.50/MWh, supplier revenues for energy and reserves increase by approximately \$1.1 billion, and uplift is reduced by approximately \$80 million. To reiterate, Case B is identical to Case A except the full unit commitment is re-solved in Case B.

¹⁶ Uplift values reported with the simulation results are based on resources that are scheduled to operate in the simulation but do not collect enough market revenues to cover their operating cost over the day. PJM's current market rules perform this calculation over run segments. The implementation of segment-based make whole payments is not performed in this calculation.

There are two effects that cause these changes:

- a. As noted previously, running the case with full unit commitment removes the uncertainty because the final operating conditions are known.
- b. The unit commitment now takes into account the need for 10-minute reserve and not Day-ahead Scheduling Reserves. This simulates the result of making commitment decisions in the day-ahead market with knowledge of the 10-minute reserve requirements that exist in real-time, rather than modeling the Day-ahead Scheduling Reserve requirement.

This in turn leads to the following results. First, the bid production cost in Case B goes down because the unit commitment is more optimal than what could be achieved in Case A. The bulk of Case A's unit commitment was provided by the PJM day-ahead market which was done based on bid/offer data that includes some level of uncertainty about real-time and a Day-ahead Scheduling Reserve requirement, instead of the 10-minute reserve requirements which are modeled in real-time. Case B's unit commitment has no uncertainty and therefore the commitment is more optimal than Case A. Second, because the Case B commitment is more optimal, there is less uneconomic supply running at costs above the LMP, higher market prices due to less price suppression, and significantly less uplift.

41. It is impossible to determine the exact portion of the difference between the two cases that results from re-solving the full unit commitment against known real-time conditions versus the effect of changing from the Day-ahead Scheduling Reserve requirement to the 10-minute reserve requirements. However, given the small size of the 10-minute reserve market in comparison to the large size of the PJM pool (approximately 1,650 MWh versus over 100,000 MWh) and the very low reserve clearing prices for reserves revenues in Case B, it is likely that the overall impact of imposing 10-minute reserve requirements on the unit commitment problem instead of the Day-ahead Scheduling Reserve requirement is very small, if not negligible. It is therefore likely that the majority of the difference can be attributed to re-solving the full unit commitment. The benefits associated with the full re-solve of the unit commitment problem based on known real-time operating conditions are not attainable under any market design because the final operating conditions are not known at the time commitment decisions are made. Therefore, the impact of this on the simulation results must be removed to determine the true impact of PJM's proposal. To achieve this, PJM's simulation of its full proposal must be compared against Case B as opposed to Case A.
42. As stated previously, to simulate impacts on the market of its full proposal, PJM utilized the same simulation software configured with the new market rules and re-solved the full unit commitment problem. The results of this simulation are in the column labeled Case C. Cases A and B are also provided for comparison.

Table 4. Case C - Simulation of PJM's Proposal with Full Unit Commitment

Variable	Case A	Case B	Case C
	Current Market Rules with Tier 1 Removed (Partial Unit Commitment)	Case A with Full Unit Commitment	PJM Proposal with Full Unit Commitment
Load Weighted LMP (\$/MWh)	35.80	37.30	37.76
Generator Energy Revenue (\$M)	26,801	27,946	28,312
Weighted Synchronized Reserve MCP (\$/MWh)	1.99	2.58	7.89
Weighted Non-Synchronized Reserve MCP (\$/MWh)	1.03	1.26	3.97
Weighted Secondary Reserve MCP (\$/MWh)	N/A	N/A	0.00
Hourly Average Cleared Synchronized Reserve (MW/hour)	1,818	1,818	3,168
Hourly Average Cleared Non-Synchronized Reserve (MW/hour)	634	634	678
Hourly Average Cleared Secondary Reserves (MW/hour)	N/A	N/A	1,943
Hourly Average Cleared Total Reserve (MW/hour)	2,452	2,452	5,789
Total Cleared Synchronized Reserve (millions MWh)	15.5	15.5	26.9
Total Cleared Non-Synchronized Reserve (millions MWh)	5.4	5.4	5.8
Total Cleared Secondary Reserve (millions MWh)	N/A	N/A	16.6
Reserve Revenue (\$M)	36.4	46.8	235.9
Uplift (\$M) ¹⁷	109.9	30.4	26.8
Bid Production Cost (\$M)	13,230	13,121	13,152
Total Energy and Reserve Market Revenues (\$M)	26,838	27,993	28,548

43. To determine the effect of PJM's proposed ORDCs, the relevant cases to compare are Case B and Case C. The difference between these simulations is only the change in the ORDCs and the addition of the 30-minute Reserve market. The effect created by removing uncertainty from the unit commitment process is removed since the unit commitment is re-solved in both cases. Table 5 provides a high-level comparison of Cases B and C.

¹⁷ Uplift values reported with the simulation results are based on resources that are scheduled to operate in the simulation but do not collect enough market revenues to cover their operating cost over the day. PJM's current market rules perform this calculation over run segments. The implementation of segment-based make whole payments is not performed in this calculation.

Table 5. Effect of PJM's Proposal

Variable	Case B	Case C	Case C minus Case B	Difference
	Case A with Full Unit Commitment	PJM Proposal with Full Unit Commitment		
Load Weighted LMP (\$/MWh)	37.30	37.76	0.46	1.23%
Generator Energy Revenue (\$M)	27,946	28,312	366	1.31%
Weighted Synchronized Reserve MCP (\$/MWh)	2.58	7.89	5.31	205.81%
Weighted Non-Synchronized Reserve MCP (\$/MWh)	1.26	3.97	2.71	215.0%
Weighted Secondary Reserve MCP (\$/MWh)	N/A	0.00	N/A	N/A
Hourly Average Cleared Synchronized Reserve (MW/hour)	1,818	3,168	1,350	74.26%
Hourly Average Cleared Non-Synchronized Reserve (MW/hour)	634	678	44	6.94%
Hourly Average Cleared Secondary Reserves (MW/hour)	N/A	1,943	N/A	N/A
Hourly Average Cleared Total Reserve (MW/hour)	2,452	5,789	3,337	136.09%
Total Cleared Synchronized Reserve (millions MWh)	15.5	26.9	11.4	73.55%
Total Cleared Non-Synchronized Reserve (millions MWh)	5.4	5.8	0.4	7.41%
Total Cleared Secondary Reserve (millions MWh)	N/A	16.6	N/A	N/A
Reserve Revenue (\$M)	46.8	235.9	189.1	404.06%
Uplift (\$M) ¹⁸	30.4	26.8	-3.60	-11.84%
Bid Production Cost (\$M)	13,121	13,152	31	0.26%
Total Energy and Reserve Market Revenues (\$M)	27,993	28,548	555	1.98%

44. When 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. The major differences between Cases B and C are the increases in committed reserve amounts, reserve prices, and reserve revenues for suppliers. This is intuitive given the change in the ORDC. The total reserve revenues increase by \$189.1

¹⁸ Uplift values reported with the simulation results are based on resources that are scheduled to operate in the simulation but do not collect enough market revenues to cover their operating cost over the day. PJM's current market rules perform this calculation over run segments. The implementation of segment-based make whole payments is not performed in this calculation.

million from the \$46.8 million in Case B. This is a large increase in reserve revenues, however, it represents about a 0.68% increase in total revenues compared to the \$27,993 million originally from Case B. The total estimated impact on energy and reserve billing of the PJM proposal is approximately \$555 million.

45. The simulation PJM conducted previously during the stakeholder process leading up to the filing of PJM's proposal showed a significantly greater impact of the PJM proposal. In fact, the prior simulation showed a total estimated impact on energy and reserve billing of approximately \$1.5 billion. PJM attributes the difference to the fact that in its prior simulation, Case A was used as the reference for comparison. This was done because the desire has always been to compare the proposal against the status quo. However, those comparisons do not recognize the impact that re-solving the full unit commitment has on the simulation. A comparison of Case B and Case C appropriately recognizes this impact. Additionally, because the difference between Case A and Case B is not achievable, because it would require bids and offers to be submitted into the day-ahead market with perfect foresight into the next operating day, it is necessary to use Case B as the base case to determine the impact of the PJM proposal.

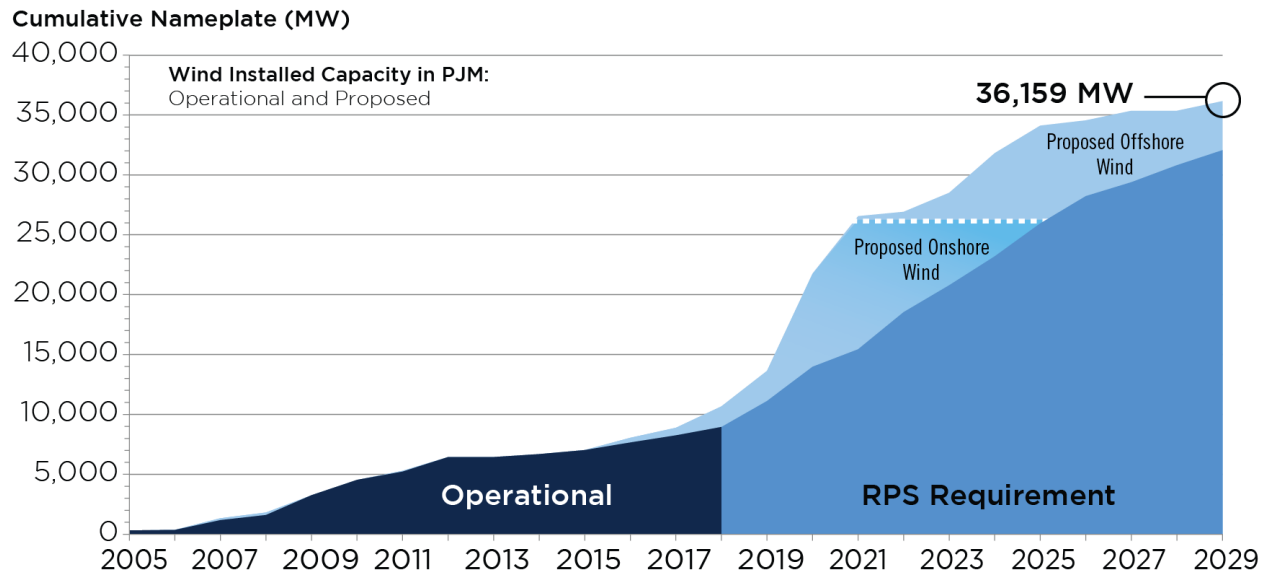
c. Estimated Total Impact - \$556 million

46. PJM estimates the increase in energy and reserve market billing from its proposal to be approximately \$556 million. This is based on the net increase in costs from the removal of the Tier 1 product of \$1.0 million plus \$555 million increase in energy and reserve billing resulting from the ORDC and the addition of the 30-minute reserve market. It is important to note that there will be offsetting savings that are not quantified here including anticipated reductions in the capacity market costs due to an increase in energy and reserve market revenues. Additionally, the energy and reserve markets provide incentives for availability during all hours, flexibility, and a low incremental cost of production. The capacity market does not explicitly incentivize these qualities that are beneficial to consumers. PJM believes that over the long-term, consumers will realize additional benefits due to stronger incentives in these areas.

D. The Need to Send Strong Incentives for Resource Flexibility

47. It is clear there is a significant push to increase the penetration of renewable energy on the PJM system. For example, all but three states in PJM (West Virginia, Kentucky, and Tennessee) have a Renewable Portfolio Standard ("RPS") or other similar clean energy target. The growth in renewables projected from the implementation of these standards is staggering. Figure 2 below shows the projected growth in onshore and offshore wind through 2029.

Figure 2. Projected Growth of Wind Resources in PJM



48. Figure 2 shows a growth in wind energy of approximately 360% in the next ten years. Intermittent renewable energy, wind in this case, creates uncertainty for system operators due to the difficulty in forecasting the output of these resources accurately. If the existing RPSs in PJM are met, that uncertainty will increase dramatically. Today's system only has approximately 10,000 MW of nameplate wind resources that already introduce a level of uncertainty that must be acted on by system operators. Because supply and demand must be balanced, the only way to manage the current and future uncertainty that will accompany the future growth of renewables are fast-responding, controllable resources (i.e., reserves). The potential for growth in renewables is significant and it is clear that strong incentives for investment in, and retention of, resource flexibility need to be sent now to prevent future issues that may degrade reliability or risk a delay in the implementation of state policies.
49. The downward-sloping ORDC that is based on measured forecast uncertainty will send a clear signal to attract the needed flexibility to manage the projected widespread integration of renewable resources. The benefit of this type of curve is that it is dynamic and can expand as the amount of renewables in PJM increases, or contract as PJM's ability to forecast the output of renewables improves. The reserves needed to meet the MRR and respond to uncertainty will be reflected consistently in the reserve demand and market prices and provide transparent market signals for asset owners to invest in the flexibility needed to maintain reliability.

E. Discussion on Price Suppression Caused by Biasing

50. As discussed in Mr. Pulong's affidavit, PJM operators frequently utilize the ability to bias Intermediate Term ("IT") SCED cases to manage system uncertainty and ensure sufficient resources are online to serve load and maintain minimum reserve requirements. While this process is better than committing a resource completely out-of-market, it has drawbacks. By biasing the IT SCED case, the operator is signaling to the dispatch

software that they require more supply (energy) to be on the system than the other input data (load forecast, renewable forecast, net interchange, etc.) would otherwise indicate. If the system operator biases an IT SCED base by 500 MW, it is the equivalent of adding 500 MW of load to the load forecast. In response to this, the IT SCED will commit/dispatch the least cost set of resources required to serve the load forecast plus 500 MW and maintain minimum reserve requirements. If the operator intervention is exactly right, prices are calculated reflecting the need for the additional 500 MW, the energy and reserve prices will generally be higher than what they otherwise would have been without the operator intervention, and there are no ill-effects of the intervention. Unfortunately, despite the experience of PJM system operators, they are rarely, if ever, exactly right with the selected biases.

51. From the system operators' perspective, it is always better to be long than short. The consequence of paying uplift by guessing the bias too high is always less than incurring a reserve shortage or worse if the submitted bias is too low. However, in the market context, uplift is a problem, especially when it is created by manual intervention into the market. Uplift is created when the bias selected by the operator is above what is actually needed to meet load and reserve needs, and the operator acts on the recommendations provided to them by the IT SCED tool.
52. For example, assume that instead of entering a 500 MW bias in the prior scenario, the operator submitted 1,000 MW. Given the size and variability of the PJM system, a 1,000 MW error in the forecasted inputs to the dispatch tools is not uncommon. Also assume that in response to that bias, the IT SCED tool recommends that the operator commit 750 MW of incremental generation and makes up the remaining 250 MW by dispatching up resources that are already online. Once the committed resources come online, it is apparent that the operator only needed 500 MW instead of 1,000 MW. When this happens, prices are suppressed.
53. The price suppression in this example occurs because resources that have a lower incremental offer than the 750 MW of incremental generation called on by the operator are reduced to "make room" for the additional 750 MW. In the LMP calculation, the goal is to set the marginal clearing price at the lowest cost to serve the next increment of load. When this problem is solved, the solution is to dispatch up the resources with low incremental cost that were dispatched down to accommodate the 750 MW. This sets the LMP for all resources on the system at a level lower than the cost of the 750 MW. Reserve market prices are also suppressed because of the reduction in the LMP. This is how the current market operates and reflects how the bias can create uplift.
54. An intuitive solution would be to have the operator adjust the reserve requirement based on their expectation of the system uncertainty and therefore their need for additional reserves. This is the solution proposed by the PJM ORDC. The operator's expectation of uncertainty is built into the ORDC and therefore is systematically determined based on historical information and is not left up to judgement. It is calculated consistently every time. The intent of building this into the reserve demand is to remove the need for the operator to manually intervene into the case based on judgement. It will not remove every instance of this because, by definition, net load error (uncertainty) can exceed the

historical analysis that is used to derive PJM's ORDCs. However, PJM anticipates the need for manual intervention will significantly decrease.

F. Synchronized Reserve Penalty Value

55. Another component of the PJM proposal is a reduction in the offer cap for Synchronized Reserves from the Variable Operations & Maintenance ("VOM") cost associated with providing Synchronized Reserves plus up to a \$7.50/MWh margin adder to the expected value of the Synchronized Reserve Penalty. PJM has proposed to change this offer cap primarily because during stakeholder discussions it was determined that the VOM portion of the Synchronized Reserve Offer cap is duplicative with VOM costs that are also able to be included in energy offers, and, the basis for the \$7.50/MWh margin adder is questionable because it was based on historic reserve market revenues from prior to the implementation of the market in 2002.
56. To replace the existing offer cap, PJM proposes using the expected value of the Synchronized Reserve penalty. This value has been estimated to be \$0.02/MWh for 2018. To arrive at this value, PJM used actual Synchronized Reserve penalty and event data. The calculation was performed as follows.
57. In 2018, there was a total of 393 MWh of Synchronized Reserve event shortfalls that received a penalty. Over that shortfall, there was a total of \$219,839.52 collected in penalties. This results in an average penalty rate of approximately \$556.84/MWh. This average rate must then be multiplied by the probability of an event occurring where compliance is measured (an event with a duration of at least ten minutes) and the probability of underperforming on average. In 2018, the total duration of Synchronized Reserve events that were in excess of ten minutes was 79 minutes. Those 79 minutes divided by the total number of minutes in a year (525,600) results in a 0.015% chance that a Synchronized Reserve event is effective in any minute of the year. The average Tier 2 performance in 2018 was 74.2% which means that the average underperformance is 25.8%. Therefore, the expected value of the penalty is calculated as follows.

Expected Value of Synchronized Reserve Penalty = Average Penalty Rate (\$/MWh) *
Probability of an Event * Probability of Underperformance

Expected Value of Synchronized Reserve Penalty = \$556.84/MWh * 0.015% * 25.8%

Expected Value of Synchronized Reserve Penalty = \$0.02/MWh

58. PJM plans to reassess this value periodically so that the new offer cap is aligned with the market results on which it is based.
59. This concludes my affidavit.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

)

Docket No. ER19-__-000

PJM Interconnection, L.L.C.

)

Docket No. EL19-__-000

VERIFICATION OF ADAM KEECH

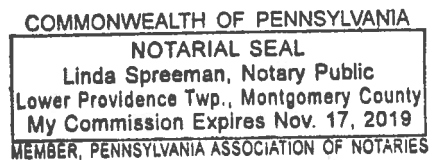
Adam Keech, being first duly sworn, deposes and states that he is the Adam Keech referred to in the foregoing document entitled "Affidavit of Adam Keech," that he has read the same and is familiar with the contents thereof, and that the testimony set forth therein is true and correct to the best of his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



Subscribed and sworn to before me, the undersigned notary public, this 28th day of March, 2019.



Notary Public



Attachment E

Affidavit of Christopher Pilon 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-____-000
	)	
PJM Interconnection, L.L.C.	)	Docket No. ER19-____-000

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

1. My name is Christopher Pilon. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403. I am Director, Dispatch, of PJM Interconnection, L.L.C. (“PJM”). I am submitting this affidavit on behalf of PJM in support of its proposed reserve market reforms in this proceeding.
2. Specifically, in this affidavit I provide support for PJM’s proposals to reform its Operating Reserve Demand Curves (“ORDCs”) and to consolidate its Tier 1 and Tier 2 Synchronized Reserve products.

I. QUALIFICATIONS

3. I joined PJM in November of 2001. As Director, Dispatch, I am responsible for the oversight and operation of the Valley Forge and Milford Control Centers. This function includes ensuring the reliable operation of the power grid, in accordance with all PJM and North American Electric Reliability Corporation (“NERC”) reliability standards pertaining to the functions of Reliability Coordinator, Balancing Authority, and Transmission Operator. In addition, I am responsible for ensuring the efficient economic dispatch of the system under the existing PJM market rules and neighboring Joint Operating Agreements. Prior to this position, I served as a Reliability Engineer and then the Manager – Reliability Engineering. As the Manager for the Reliability Engineering group, I managed the group responsible for coordinating day-ahead and real-time operating plans between PJM, its members Transmission Owners and Generation Owners, and our neighboring entities. As a Reliability Engineer prior to this, I performed these functions directly.
4. I hold a Bachelor of Science degree in Electrical Engineering from Lehigh University and a Master of Business Administration from Villanova University.

II. OPERATOR ACTIONS (ORDC CURVES)

5. In understanding operator actions to schedule generation and reserves, it is important to remember the prime responsibility that PJM has in the control room—reliability. PJM has the reliability responsibility to ensure that supply and demand are balanced at all times. This includes maintaining the current system balance and all reserve requirements, as well as continually forecasting and planning to ensure that the generation dispatcher is

directing the necessary actions to be taken by the generation owners, to ensure that system balance and reserve requirements are maintained as we progress through the Operating Day. The reserves maintained are regulating reserves, Synchronized Reserves, and Primary Reserves.¹ These tasks—forecasting and planning—are key items that warrant further explanation, and are detailed as follows.

A. *Forecasting*

6. The components of the forecasts that are most critical to maintaining real-time power balance are load forecasting, interchange forecasting, and generation performance/availability forecasting. PJM has automated tools that develop these forecasts, as well as PJM staff members that maintain and calibrate these automated tools to ensure that they are as accurate as possible. However, some level of error will always be present in forecasts because PJM does not have perfect vision into the future. To account for this error, the operators carefully monitor the actual load, interchange, and generation performance/availability against their forecasted quantities. The operators use this information, along with the PJM dispatcher’s operating experience, when performing the next step in the process—planning to maintain system balance and reserves.

B. *Planning*

7. In the near real-time horizon, the primary planning tool used to maintain system balance and reserves is the Security Constrained Economic Dispatch (“SCED”) application.² This application is composed of two separate optimization engines: Intermediate Term SCED (“IT SCED”) and Real-time SCED (“RT SCED”). IT SCED is utilized to call on quick-start generation, such as combustion turbines. RT SCED does not recommend additional generation. Instead, its function is to co-optimize the energy and reserves for online resources to meet demand, along with the associated basepoints and pricing signals.

C. *Bias*

8. As noted above, IT SCED is the forward-looking energy and reserve co-optimization engine that is utilized by the PJM generation dispatcher to determine if and when quick-start generation needs to be scheduled on (or off) to maintain power balance and reserve requirements. The engine looks at multiple time intervals beginning between 30-minutes and 2-hours ahead. The engine begins with a snapshot of the real-time system using the PJM Energy Management System (“EMS”) state estimator case. This case includes the real-time load, generation, system topology, and interchange. The engine then uses the aforementioned forecasts to project the total change in system demand and how to meet that demand change. Based on the forecasts, it will recommend resources that can start within 2-hours and have a Minimum Run Time of 2 hours or less for the PJM dispatcher to commit. However, the flaw in this approach is that the optimization is based on the assumption that the forecasts are perfect and that every generator responds exactly as

¹ PJM also maintains a calculation that estimates real-time 30-minute reserves, for situational awareness purposes.

² Beyond this, PJM also uses tools such as the Ancillary Services Optimizer (“ASO”) and Security Constrained Unit Commitment.

their parameters state. The generation dispatcher knows that this will not be true. To account for this error in forecasts and generator response that they observe on a daily basis during real-time operations and based on past operating experience, the dispatchers ‘bias’ the cases.

9. This bias is a catch-all value to account for all possible errors in the forecasts. Its effect is to increase (or decrease) the amount of net demand that the IT SCED solution will optimize for and therefore recommend that additional (or reduced) resources be committed. For example, during a morning load pick-up when demand is increasing rapidly, the dispatcher may bias the cases by 2,000-3,000 megawatts (“MWs”) to account for faster-than-expected load, lower-than-expected generation, and generators that are slow to ramp-up. Use of a bias, and the amount of the bias, are based on the dispatcher’s training, experience, and judgement. However, it is important to note that this bias is not developed formulaically or in a manner that is 100 percent consistent from dispatcher to dispatcher. That said, in the current market construct, the bias is an absolute necessity to ensure reliability given the uncertainty in the forecasts used in the commitment process.
10. The overall impact of the IT SCED bias is that it allows the dispatcher to operate the system with a reasonable safety margin by scheduling additional resources in the 30-120 minute time horizon. As a result, if the real-time load does come in higher, generators are not available or do not perform as expected, interchange is higher than forecast, etc., the IT SCED bias ensures that adequate generation is online and available for the RT SCED engine to use to meet the demand and reserve requirements. Having sufficient resources available to meet the demand and reserve requirements also prevents PJM from entering into emergency procedures, as would be required by NERC reliability standard EOP-011 and PJM Manual 13, section 2.2.
11. The actions above are prudent steps the PJM dispatchers need to take to ensure reliability. However, as noted above, the value for the IT SCED bias is not a formulaic value. Also, the error associated with the forecasts mentioned previously may be smaller than expected or even in an opposite direction to the bias applied to the IT SCED case. For example, the dispatcher may see renewable generation performance trending below the forecasted output in real-time and bias the case accordingly, but that could very quickly change to over performance of the renewable generation. As a result, if the IT SCED bias does not perfectly match the real-time conditions that ultimately develop, PJM will have potentially scheduled additional generation that is not needed by the RT SCED engine and ultimately does not set price and may even suppress prices, as explained in Mr. Adam Keech’s affidavit.³ These extra system reserves did serve a purpose when called, to account for forecasting and generator response error, but are not properly priced in real-time because the market does not reflect the true demand for reserves. This leads to uplift and price suppression and needs to be corrected.
12. In practice, this operator bias operates in many cases like Synchronized Reserves, when it assumes additional demand, above expected demand, as a means of addressing

³ Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C. ¶¶ 50-54, included as Attachment D to this filing.

uncertainty, and commits generation to balance that assumed additional demand. This type of bias, known as “positive” bias because it adds demand, operates like reserves in another, very critical, fashion—it has often helped the system avoid entering a reserve shortage. Looking back at the 2018 calendar year, for example, if the MWs of positive bias actually applied by operators were removed from the balance, PJM’s real-time EMS would have shown the system short on reserves in over 29 percent of the five-minute intervals making up that year.

13. Table 1 below summarizes the results of PJM’s review of the 2018 data. To better understand the data, it helps to remember the background I explained above, and add a few more details. The IT SCED engine looks ahead up to two hours. The RT SCED engine looks ahead ten minutes. Both engines permit the operator to vary the dispatch schedule in those engines by using biases. The bias applied by the operator, whether positive or negative, is recorded for each five-minute interval. Shortage pricing is triggered only if the dispatch schedule in RT SCED shows that reserves are below the Minimum Reserve Requirement (“MRR”), including the 190 MW second step. The EMS then displays the actual supply and demand, and actual reserve levels, in real-time.
14. Turning now to Table 1, the first column labeled ‘Synchronized Reserve Surplus’ categorizes the varying levels of synchronized reserves that were measured using real-time conditions from EMS relative to the MRR, including the 190 MW second step on the current ORDC. In other words, this represents the reserves that were ultimately available on the system after the IT and RT SCED dispatch instructions were implemented. The second column lists the exact number of five-minute intervals these reserve levels were observed. The relative percentage is then listed in the third column. The fourth and fifth columns represent IT SCED bias information and potential ‘Synchronized Reserve Surplus’ change that would have been realized if the IT SCED bias was removed.
 - a. The RT SCED case operates on a ten-minute look-ahead. If a reserve shortage exists in actual system operations represented in EMS right now, but the RT SCED case can “cure” the reserve shortage by re-dispatching online generation within the 10-minute look-ahead window, it will not produce dispatch solutions to the operator that indicate a reserve shortage despite there actually being one currently.
 - b. Notwithstanding the 10-minute look-ahead, conditions will be different between the approved RT SCED case and actual operations because the forecasts are not 100 percent accurate and resources do not operate identically to how their offer parameters indicate they can.
15. Keeping in mind that reliability is the number one priority for PJM operators, it is for this reason that PJM system operators use the bias capability available to them to ensure that, to the greatest extent practicable, the system needs are met. Approving an IT SCED case that commits more supply than is required by the load forecast and minimum reserve requirements to avoid a potential reserve shortage, rather than one that operates the system on the razor’s edge is evidence of that. In some cases, however, despite

conservatively scheduling additional generation, the actually experienced real-time conditions in EMS will show reserves below the MRR. In 2018, this happened in real-time in 2,995 five-minute intervals, i.e., 2.8 percent of all such intervals in 2018. It should be noted that not all EMS observed real-time shortage result in an RT SCED shortage due to the following:

- a. The RT SCED case operates on a ten-minute look-ahead. If a reserve shortage exists in actual system operations represented in EMS in real time, but the RT SCED case can “cure” the reserve shortage by re-dispatching online generation within the 10-minute look-ahead window, it will not produce dispatch solutions to the operator that indicate a reserve shortage despite there actually being one currently.
 - b. Notwithstanding the ten-minute look-ahead, conditions will be different between the approved RT SCED case and actual operations because the forecasts are not 100 percent accurate and resources do not operate identically to how their offer parameters indicate they can.
16. Continuing in Table 1, the fourth column shows the average MWs of positive bias applied per reserve quantity bin. As I noted above, operator-applied bias is recorded for every five-minute interval, and may be positive or negative. This column shows the average amount of bias in all five-minute intervals where *positive* bias was applied, grouped by reserve surplus (or shortage) condition. If that positive bias resulted in additional resource commitment recommendations greater than or equal to the amount of the shortage that would have occurred absent the positive bias, and the system operator took action on those recommendations, then those biases avoided potential reserve shortages that otherwise could have occurred. By subtracting the positive bias values from the original reserve levels from the EMS data, a new reserve quantity can be calculated that reflects the system operator not entering the bias. To 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. Based on this analysis, it is possible that in 29.1 percent of all five-minute intervals in 2018, PJM system operators would have been short reserves absent the positive bias applied in the scheduling engines for that interval. The average amount of positive bias applied in such cases, i.e., the amount of increased demand, was 1,471 MWs.

Table 1.

Synchronized Reserves Surplus	Intervals	Percentage of Intervals	Average Operator Positive Bias (MWs)	Percentage of Intervals (Bias Removed)
< zero MWs	2,955	2.8%	1471	29.1%
zero to 250 MWs	18,475	17.6%	558	13.3%
250 MWs to 500 MWs	25,051	23.8%	531	15.2%
500 MWs to 1,000 MWs	32,005	30.4%	482	20.4%
greater than 1,000 MWs	26,634	25.3%	408	21.9%

17. It is important to note that the application of positive bias in these cases was necessary but not a desired outcome. It was necessary to ensure reliability to account for the uncertainty and safety margin that is not reflected in the existing ORDC, but not desired because it can result in price suppression and uplift. If the recommended ORDC curves were incorporated, the need for operators to manually intervene in SCED cases would decrease, the reserve requirements would be more reflective of actual operator needs, and prices would be more reflective of operator actions.

D. Out-of-Market Actions

18. In addition to IT SCED case biasing, which is the most prevalent manual method to scheduling additional reserves, the generation dispatchers may also take out-of-market actions to commit additional generating reserves manually. This will occur for conditions the IT SCED bias is not directly able to account for, such as the need for longer lead generation that must be committed prior to the IT SCED two-hour window or if there is a locational need for the reserves due to major transmission constraints.
19. As stated above, the PJM dispatchers need to utilize the bias and out-of-market commitments to account for load, generation, and interchange forecasting errors. Under the status quo, this practice of biasing and committing generation outside of the market cannot change. Limiting the generation dispatcher's ability to account for forecast uncertainty through biasing IT SCED and/or taking out-of-market actions, without developing a market mechanism to ensure availability of sufficient reserves, would lead to operating unreliably. That is not acceptable.
20. In addition, in the status quo, the MWs committed as a result of this bias and out-of-market commitments will continue to be at risk of suppressing system price until a market solution is developed that limits the bias and out-of-market commitments and better aligns reliable operations and pricing. The ORDCs proposed by PJM provide a formulaic approach to account for forecasting errors that will be applied consistently in operations across all shifts and generation dispatchers and will provide the transparency necessary to PJM members to manage their assets appropriately. Most importantly, the ORDC proposal will significantly increase the likelihood that the resources needed to maintain the reliable operation of the grid are reflected in the reserve and energy prices that result from the markets. Accurate pricing is critical to providing the incentives for physical asset owners to act in a manner that reinforces grid reliability, the primary function of the markets that PJM operates.

III. TIER 1 / TIER 2 CONSOLIDATION

21. As indicated in NERC standard BAL-002, PJM must maintain reserves to respond to the loss of the largest single contingency in the PJM system. PJM must deploy these reserves if an unplanned generation loss occurs. This recovery must take place within 15 minutes. To ensure compliance with this requirement, PJM utilizes a combination of Synchronized and Primary Reserves that must respond within 10 minutes. This allows for a buffer between the time needed to convert all reserves to energy and the 15-minute requirement

established by the BAL-002 standard. Further, PJM needs to have accurate estimates of available reserves and the reserves need to respond as expected when deployed.

22. There are two types of Synchronized Reserve products under PJM's current market rules—Tier 1 and Tier 2. Tier 1 is provided from non-emergency resources that are on-line and generating, but not fully loaded, and that can provide additional energy within 10 minutes with no departure from their energy profit maximizing economic dispatch point. A simple example of a Tier 1 resource would be a partially loaded generator that has remaining capability to increase its output in response to PJM's request to deploy reserves. Tier 2 resources are those resources that must be dispatched away from their energy profit maximizing dispatch point in order to maintain their reserve capability. Tier 2 resources include generators that would have been producing at their maximum output to maximize their energy profits but have been requested by PJM to reduce their output to create reserve capability. Tier 2 also includes synchronous condensing resources that incur costs to start from an offline state to synchronize to the grid in order to be prepared to deploy their reserves at PJM's request.
23. The first step in ensuring reserve adequacy occurs approximately one hour prior to the operating hour when PJM runs the ASO.⁴ In terms of reserve adequacy, this tool has two primary functions: (1) determine if there is a need for any Tier 2 reserves in the operating hour, and, if so, (2) determine if the most economic set of Tier 2 resources contains any synchronous condensers or demand resources that require advanced notification of a commitment and therefore cannot be co-optimized in real-time. These resources that cannot be co-optimized in real-time and require advanced notification of a Tier 2 reserve assignment are committed by the ASO tool. The ASO estimates the amount of Tier 1 that will be available on the system during the study hour solely for the purpose of determining whether any Tier 2 resources may be needed. These Tier 1 estimates are recalculated in real-time by both the IT SCED and RT SCED engines based on real-time data. Once the Tier 1 estimate is calculated, the total available Tier 1 is compared to the MRR plus 190 MWs, which is typically largest single generator contingency plus 190 MWs. If the total Tier 1 is greater than the MRR plus 190 MWs, no Tier 2 reserve is assigned by the ASO. If the total Tier 1 is less than the MRR plus 190 MWs, Tier 2 is required and ASO will make the most cost-effective assignments based on all available resources. The only output from the ASO that feeds the real-time dispatch functions are the Tier 2 commitments on resources that cannot be co-optimized in real-time such as demand response resources and synchronous condensers.
24. As explained above, PJM re-estimates the amount of Tier 1 reserves it has in real-time in each solution of the RT SCED engine. However, as noted above, Tier 1 does not have an obligation to respond and is not given a true assignment of reserves. It is only an estimate of what response a unit is technically capable of, but not a guarantee it will achieve it. This is an important distinction—capability versus response. To ensure the response can be counted on, PJM has taken many steps to better align its Tier 1 estimate to be more reflective of expected response of the generator. This process of whittling down the Tier 1 response estimate initially began with a review of a lengthy synchronized

⁴ The ASO also commits the set of resources that will provide regulation during the operating hour.

event in September 2013 where response was well below capability. The adjustments that have been implemented to date include:

- a) Ramp rate adjustments: the RT SCED engine decreases the generator owner-submitted ramp rate parameter via the ‘degree of generator performance’ calculation. This is a calculation PJM’s RT SCED application performs to compare a generator’s submitted ramp rate to the generator’s actual ramp rate by measuring its ability to follow PJM basepoints over the past 30 minutes. Using this parameter can result in a better Tier 1 estimate, but it does not incent generator owners to enter more accurate data into the PJM market systems.
 - b) Tier 1 maximum: RT SCED will cap the Tier 1 estimate for a generator to the lower of its spin maximum (“spin max”) versus Economic Maximum (“eco max”). The spin max is a value entered into Markets Gateway by the generation operator and reflects the maximum output of the unit that they are offering into the Synchronized Reserve Market. If the spin max is greater than its eco max, this is an indication that additional non-automated actions may be taken to achieve the additional MWs, such as entering a duct firing range, topping coal or gas-fired generators with oil sprays, etc. These are actions that are only implemented when a unit has a Tier 2 reserve assignment.
 - c) Tier 1 “deselecting”: based on historic unit type response, PJM ‘deselects’ or removes all hydro, combustion turbines, and renewable resources from being eligible to provide Tier 1 reserves unless the generator operator requests an exception to this and can prove they are able to respond to Synchronized Reserve events. In addition, based on unit-by-unit past performance, PJM will selectively remove generators from having any Tier 1 estimates if they are not a reliable resource. This is an ongoing process adjusted periodically.
25. In addition to the calculation changes above, PJM has continued to emphasize accurate submittal of generator parameters and continued its generator outreach. As an example, see the presentation from the May 2018 PJM Operating Committee.⁵
26. However, in spite of our efforts to improve the response rate of Tier 1 resources, PJM continues to see poor response rates from Tier 1 estimated generators, as evidenced by the data in the Independent Market Monitor’s State of the Market Reports.⁶ Given the historically poor response rates of Tier 1 resources, PJM dispatchers must take the action necessary to ensure they have sufficient reserves to maintain reliability and respond to a large generator loss. These actions may include:

⁵ PJM Interconnection, L.L.C., *Synchronous Reserve Tier 1 Performance Improvement Recommendation Update* (May 1, 2018), <https://www.pjm.com/-/media/committees-groups/committees/oc/20180501/20180501-item-21-tier-1-evaluation.ashx>.

⁶ See Monitoring Analytics, LLC, *State of the Market Report for PJM*, at 416 (Mar. 9, 2017), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-volume2.pdf; Monitoring Analytics, LLC, *State of the Market Report for PJM*, at 460 (Mar. 8, 2018), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017-som-pjm-volume2.pdf; Monitoring Analytics, LLC, *State of the Market Report for PJM*, at 473 (Mar. 14, 2019), http://www.monitoringanalytics.com/reports/pjm_state_of_the_market/2018/2018-som-pjm-volume2.pdf.

- a) Manually assigning Tier 2 reserves intra-hour.
 - b) Reducing the ASO Case Tier 1 estimate via a “Tier 1 bias” that can be manually entered. This may result in the assignment of additional inflexible Tier 2 reserves.
 - c) Planning to meet the contingency recovery requirements by using Non-Synchronized (Primary) Reserves.
27. The dispatchers need to have generator reserve estimates that are accurate. They also need to have confidence that the reserves will respond when deployed. The current market rules do not penalize lack of performance of Tier 1 resources and therefore, response is not consistent with needed or expected behavior. The disconnect between estimated response and actual response leads to out-of-market actions by dispatchers to maintain reliability that can suppress market prices (as noted above and explained by Mr. Keech). These are all clear indicators that the market needs to be corrected to incent accurate response, penalize non-response, and price all reserves accurately and according to their value. A proper market design which values reserves appropriately and transparently through the market will not only support reliability but also incentivize investment in new resources that will provide additional flexibility and efficiency. The first step towards this is to eliminate Tier 1 and combine it with Tier 2 into one Synchronized Reserve product. As referenced above, analysis has indicated that Tier 1 is not a reliable resource. If it is not reliable, it should not be the foundation from which PJM builds its reserve products and should not be used for triggering the Tier 2 market clearing. Assigning, compensating, and penalizing all resources based on their submitted parameters, not PJM-adjusted parameters, will align the market signals with the operating needs.

IV. 30 MINUTE RESERVES

28. Currently, PJM maintains three short-term reserve products—Synchronized Reserve, Primary Reserve, and regulating reserve. The main purpose for Synchronized and Primary Reserves are to ensure compliance with BAL-002 to recover from a major contingency loss. Regulating reserve is used to manage small aberrations in system demand from forecast. PJM also maintains a Day-ahead Scheduling Reserve (“DASR”) requirement to account for average load forecast errors and forced generator outages between the day-ahead and real-time operating horizons. However, there are other risks to the reliability of the power grid that are not currently accounted for during the operating day but must be considered as the industry evolves and changes, particularly from a fuel and resource perspective.
29. Over the past several years, the PJM system and the industry in general have seen an abundance of new generation coming online. The majority of this generation is natural gas-fired generation. Due to the nature of natural gas being a ‘just-in-time’ fuel delivery system, a new risk to the power grid has emerged. With multiple generators sharing a common pipeline as their source of just-in-time gas delivery, there is a new common mode failure condition whereby the loss of that pipeline could result in the loss of multiple generators. The impact could be more severe from a MW perspective than the largest single generator contingency for which Synchronized and Primary Reserves are

designed to recover from. That said, there is an important distinction to be made between an electric system common mode failure and a pipeline common mode failure—the time between infrastructure failure and system impact. When there is an electric system common mode failure that impacts one or more generators, the time between failure and loss of generation is cycles. In the case of the pipelines, the time between failure and loss of generation will be 30 minutes or longer due to pressure remaining in the pipe and the slower moving nature of gas, which is approximately 25 miles per hour compared to electricity that moves at the speed of light. Therefore, having a 30-minute Reserve Requirement in place to be prepared to respond to these potential pipeline contingencies is a more appropriate approach than increasing the Synchronized or Primary Reserve Requirements.

30. In addition to maintaining the ability to recover from a gas pipeline contingency, PJM also has a requirement to maintain compliance with BAL-002-2 R3 to restore its Synchronized and Primary Reserves within the NERC recovery period following the loss of a major generation contingency. As stated by this standard, PJM, in its role as the Balancing Authority, has the two-fold obligation to deploy reserves to maintain reliability following the loss of a large generator, which is the purpose of Synchronized and Primary Reserves, and to restore those reserves through the commitment of additional generation in real-time. PJM currently relies on the DASR to ensure those additional reserves are available to be scheduled during the Operating Day. However, as stated prior, the DASR is a day-ahead scheduled requirement that is not maintained in real time. Furthermore, the DASR is meant to account for *average* load forecast errors and forced generator outages (not under stressed system conditions with greater than normal load forecast errors and/or forced generator outages). As a result, there is no guarantee the DASR will ensure that there are sufficient resources available in the operating day to recover the Synchronized and Primary Reserves. The 30-minute real-time reserve requirement would close this gap by providing a mechanism to assign reserves and incent generators to maintain flexibility through the use of market signals.
31. This concludes my affidavit.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

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Docket No. EL19-___-000

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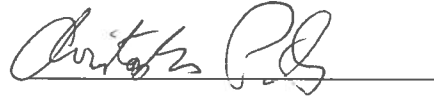
PJM Interconnection, L.L.C.

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Docket No. ER19-___-000

VERIFICATION OF CHRISTOPHER PILONG

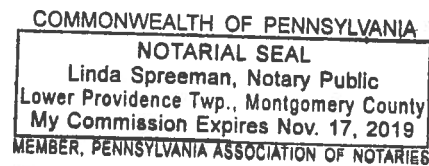
Christopher Pilong, being first duly sworn, deposes and states that he is the Christopher Pilong referred to in the foregoing document entitled "Affidavit of Christopher Pilong," that he has read the same and is familiar with the contents thereof, and that the testimony set forth therein is true and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



Subscribed and sworn to before me, the undersigned notary public, this 27th day of March, 2019.



Notary Public



Attachment F

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

**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”). I am submitting this affidavit on behalf of PJM in support of its reserve market reforms in this proceeding.
2. Specifically, in this affidavit, I provide support for PJM’s proposals to reform its Operating Reserve Demand Curves (“ORDCs”).

Qualifications

3. I joined PJM in 2011. As a Senior Engineer with the Resource Adequacy Planning department, I am responsible for performing long-term resource adequacy studies involving loss-of-load probability calculations whose results serve as inputs into PJM’s Reliability Pricing Model as well as PJM’s Regional Expansion Transmission Plan. I have also collaborated with PJM’s planning and operations groups in projects related to long-term load forecasting, short-term solar forecasting and net-interchange schedule forecasting models. Prior to joining PJM, as a graduate student/research assistant, I performed research and wrote articles on topics pertinent to restructured electricity markets, namely generation capacity expansion and financial transmission rights. I am a member of the IEEE Power and Energy Society and an active participant in interregional resource adequacy working groups.
4. I hold a Bachelor of Science degree in Industrial Engineering from University of La Frontera-Chile, and a Masters and Ph.D. degree in Industrial Engineering from the University of South Florida.

Methodology to Calculate Proposed ORDC

Overview

5. To operate the system securely and reliably, PJM must meet Minimum Reserve Requirements (“MRRs”) for the Synchronized and Primary Reserve Requirements. These requirements are established by PJM in furtherance of North American Electric Reliability Corporation (“NERC”) standards. The procurement of reserves occurs ex-

ante, based on real-time forecasts of load, wind output, solar output, net-interchange schedule, and projected availability of thermal units. However, such forecasts and projections have historically and inherently exhibited error. As Mr. Christopher Piong, Director of Dispatch, PJM, explains in his affidavit in support of PJM's proposal, while PJM has automated tools and expert staff to ensure the accuracy of its forecasts, it is not possible for PJM to have perfect foresight into the future, and thus there is a degree of error inherent in the forecasts.¹ Meeting the MRRs is thus conditioned by the uncertainties in the above forecasts and projections. In the event that any or all of the uncertainties materialize, reserves in excess of the MRRs, to the extent they are available, can make up for a potential MRR deficiency. Therefore, quantifying the probability of such uncertainties provides a path to value reserves in excess of the MRRs. The quantification of the probabilities also includes accounting for factors that mitigate the uncertainties: in particular, PJM's Regulation Requirement procured in the Regulation market, which acts as the first line of defense against the real-time uncertainties due to the fast response provided by such resources.

6. In essence, the rationale for the approach taken by PJM to derive its proposed ORDC is to calculate the probability that the total error in real-time forecasts and projections (adjusted for uncertainty-mitigating factors) is greater than various reserve levels in excess of the MRR such that the MRR cannot be met, shortage pricing is triggered, and the Reserve Penalty Factor² is used in the calculation of Locational Marginal Prices ("LMPs") and reserve market clearing prices ("MCPs"). As a result, the proposed ORDC is composed of an MRR segment and a downward-sloping segment whose shape is determined by the declining probability of failing to meet the MRR as the magnitude of total forecast error (and available reserves) increases. Consequently, when available reserves are below the MRR, the price in the ORDC is the penalty factor to signal the need for more reserves in the system and escalate prices accordingly; as reserve quantities increase in excess of the MRR, the ORDC price gradually decreases signaling that the system has better capability to deal with the real-time uncertainties that may trigger an MRR shortage.

Minimum Reserve Requirement

7. PJM must meet MRRs for Synchronized and Primary Reserves for reliability. These requirements are established by PJM in furtherance of NERC standards to respond to the loss of the largest single contingency in the PJM system or other system events that require rapid recovery. A potential MRR deficiency exposes the system to being unable to respond in time to such contingencies and therefore represents a degradation in system reliability. An incremental per megawatt production cost, referred to as a penalty factor, is associated with each MRR. These penalty factors serve as a proxy for the incremental value of reserves when the available reserves in the system are less than or equal to the

¹ See Affidavit of Christopher Piong on Behalf of PJM Interconnection, L.L.C. ¶ 6, included as Attachment E to this filing.

² The Reserve Penalty Factor represents the incremental value of reserves under shortage conditions. See Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C. ¶ 11, included as Attachment D to this filing.

MRR. In PJM's proposed ORDCs, the penalty factors are the highest price points because they are aimed at signaling the need for more reserves in the system.

Impact of Uncertainty on Meeting the MRR

8. The procurement of reserves occurs ex-ante, based on real-time forecasts of load, wind output, solar output, net-interchange, and projected availability of thermal units. PJM runs several optimization engines leading in to real-time to ensure enough energy and reserves are on the system to meet real-time demand. These include the Ancillary Service Optimizer, Security Constrained Unit Commitment and Security Constrained Economic Dispatch ("SCED"). Specifically, when the optimization engines determine the procurement and/or pricing of reserves for target time T, those reserves are aimed at addressing the uncertainties between T and T+10 (in the case of the Synchronized and Primary Reserve Requirements which are expected to be met with resources responding in ten minutes) or between T and T+30 (in the case of 30-minute Reserve Requirement). Furthermore, in the case of the RT SCED, the run is performed 10 minutes prior to the target time T, that is at T-10. This entails that all inputs used in the RT SCED run are forecasts or projections of conditions for times T, T+10, T+30 as of T-10. As referenced above, forecasts or projections inherently have errors, because PJM does not have perfect vision into the future. Such errors impact the ability of the system to meet the MRRs. Consider the following scenario: at T-10, a quantity of reserves equal to the MRR is procured based on a load forecast equal to X; but if at T+10 the actual load is higher, $X + A$, then some of the reserves (a quantity equal to A) will need to be converted into energy creating a shortfall in the MRR (total reserves will be equal to $MRR - A$), triggering the penalty factor associated with that MRR. Consider an alternative version of the above scenario: if the procurement of reserves at T-10 is $MRR + A$, then even if A reserves are converted into energy to account for the actual load being $X + A$, there would be no MRR shortfall (the total reserves ex-post will be equal to the MRR). Because in the above scenarios the quantity A by which the load forecast is too low cannot be known ahead of time, reserves on the system above the MRR have value because they can account for the situation when the extra A quantity of load actually materializes.
9. Similar scenarios can be created for the other real-time forecast and projections: wind output, solar output, net-interchange, and projected availability of thermal units. Unfortunately, the magnitude of the errors in forecasts and projections is not a constant value. Historical data shows significant variation. Thus, to quantify the uncertainties associated with these errors, historical data for each forecast and projection can be leveraged to derive probabilistic distributions of the errors. Such probabilistic distributions can then be used to estimate the probability that, for instance, using the above illustrative scenario, the load error is greater than A. The probabilities can in turn be used to determine what percentage of the time procuring $MRR + A$ reserves prevents an MRR shortfall and what percentage of the time it does not prevent an MRR shortfall, triggering the penalty factor associated with the MRR. These probabilities are the basis for the derivation of the value (i.e., the prices) of reserves in the ORDC, as discussed in the following subsections.

10. Hence, in PJM's proposal, the value of reserves is related to how likely it is the system will find itself in a reserve shortage even though at any given time the system may have more reserves than the applicable MRR. To determine how likely it is to go from being long to being short reserves, PJM will look at the probability of error in several key forecasting categories (load forecast error, wind output forecast error, solar output forecast error, net-interchange schedule forecast error, and forced outages of thermal units). In other words, establishing the value of reserves in excess of the MRR depends on the maximum value of reserves and the probability of not meeting the MRR given a specific level of reserves.

Uncertainties and Uncertainty-Mitigating Factors

11. The relevant real-time uncertainties that impact the ability of the system to meet the MRR are those associated with balancing supply and demand for energy and reserves in the dispatch case. On the demand side, the uncertainty is caused by the error in forecasting load. The load forecast model used in the RT SCED case is run every five minutes producing a forecast for the next six hours, in five-minute intervals (i.e., a total of 72 forecasted values, every five minutes). The forecast is run at the transmission-zone level.

On the supply side, the relevant uncertainties are the following:

- a) Wind Output Forecast: the wind power forecast is run every five minutes producing a forecast for the next six hours, in five-minute intervals. The forecast uses static data (e.g., maximum capacity, location, turbine manufacturer) and real-time dynamic data (e.g., measured wind speed, measured output) of PJM's wind farms in order to create a forecast for each resource's output.
- b) Solar Output Forecast: the solar power forecast is run every five minutes producing a forecast for the next six hours, in five-minute intervals. The forecast uses static data (e.g., maximum capacity, location, panel manufacturer) and real-time dynamic data (e.g., measured output) of PJM's solar sites in order to create a forecast for each resource's output.
- c) Forced Outages of Thermal Units: the availability of thermal units is impacted by full or partial forced outages that occur without advance notification. Generating facilities in the PJM footprint are required to report such outages using the PJM eGADS system. This uncertainty is not necessarily produced by the error associated with a forecast model. However, its impact on balancing supply and demand for energy and reserves is equivalent to that arising from errors in forecasting models.
- d) Net-Interchange Schedule Forecast: the net-interchange schedule forecast is run every fifteen minutes producing a forecast for the next four hours, in fifteen-minute intervals. Net-interchange is defined as the net of energy imports and exports. The model uses interchange schedules provided to PJM via the exSchedule tool.

12. Factors that mitigate uncertainty in real-time are also relevant to assess the ability of the system to meet the MRR. Such factors could be supply or demand-related but must be associated with reliably and rapidly responding to PJM's dispatch signals. Resources committed in PJM's Regulation Market meet these qualifications. PJM's Regulation Market runs every five minutes procuring resources to meet the Regulation Requirement which varies by season and time-of-day as shown in Table 1.

Table 1: Regulation Requirement

Season	Dates	Non-Ramp Hours	Ramp Hours	Effective MW Requirement
Winter	Dec 1 – Feb 29	HE1 – HE4, HE10 – HE16	HE5 – HE9, HE17 – HE24	Non-Ramp = 525MW Ramp = 800MW
Spring	Mar 1 – May 31	HE1 – HE5, HE9 – HE17	HE6 – HE8, HE18 – HE24	Non-Ramp = 525MW Ramp = 800MW
Summer	Jun 1 – Aug 31	HE1 – HE5, HE15 – HE18	HE6 – HE14, HE19 – HE24	Non-Ramp = 525MW Ramp = 800MW
Fall	Sep 1 – Nov 30	HE1 – HE5, HE9 – HE17	HE6 – HE8, HE18 – HE24	Non-Ramp = 525MW Ramp = 800MW

While there may be resources that under certain circumstances (e.g., high LMPs) become available and can mitigate the above real-time uncertainties, it is difficult to quantify the likelihood that such behavior will continue in the future (in contrast to the situation of the Regulation resources described above). Hence, PJM cannot reliably include this behavior as an uncertainty-mitigating factor in the procurement of reserves.

Look-Ahead Period for Uncertainty

13. The pricing of reserves via RT SCED occurs ex-ante based on multiple forecasts and projections. The uncertainties arising from these forecasts and projections can be quantified based on historical data. The duration of the look-ahead period to estimate the magnitude of these uncertainties (i.e., the forecasts' errors) varies depending on the reserve requirement. For the Synchronized and Primary Reserve Requirement, 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: $(T+10) - (T-10)$. Similarly, for the 30-minute Reserves, the length of the applicable interval is at least 40 minutes. PJM is proposing to use 30 minutes and 60 minutes, respectively, as the corresponding look-ahead periods for estimation of the uncertainties. The additional duration of time in the look-ahead period in each case (10 minutes for the Synchronized and Primary Reserve Requirement and 20 minutes for 30-minute Reserves) is 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, which is not captured when solving the RT SCED case for a single interval.³

³ Affidavit of Dr. William W. Hogan and Dr. Susan L. Pope on Behalf of PJM Interconnection, L.L.C., *PJM Reserve Markets: Operating Reserve Demand Curve Enhancements* at 18, included as Exhibit 1 to this filing.

Note that due to the rolling nature of the RT SCED cases, the look-ahead period for uncertainty also has a rolling nature (e.g., if the RT SCED case run at T-10 procures reserves to address uncertainty between T and T+10, then the next RT SCED case run at T-5 procures reserves to address the uncertainty between T+5 and T+15).

14. These timeframes, 30 minute uncertainty for 10 minute reserve products, and 60 minute uncertainty for the 30-minute Reserve product, also align with the operator actions available to address uncertainty within the prescribed timeframe. For example, if system uncertainty manifests in the 0-30 minute timeframe, the operator will respond to that uncertainty first (and automatically) by deploying Regulation. PJM's proposed curves address this by accounting for the supply of Regulation on the system. Second, the system operator will attempt to run the RT SCED to adjust the system based on errors in the forecast. This process deploys the reserves that the operator has assigned using the ORDC to respond to the uncertainty without violating the MRR. The final option would be to initiate a Synchronized Reserve event. All of the actions available within the 0-30 minute timeframe include the use of 10 minute reserves illustrating it as a reasonable time proxy over which to measure their value. For the 30-minute Reserve product which uses 60-minute uncertainty, the same general principles apply.

Development of Probabilistic Distributions to Quantify Uncertainty

15. The quantification of the uncertainties involves deriving probabilistic distributions of the forecast errors based on historical data adjusted to account for the uncertainty-mitigating factors, i.e., the Regulation Requirement. The assumption is that, in the future, similar levels of uncertainties can be expected. The key elements in the development of the probabilistic distributions are as follows:
 - a) Using historical data from the most recent three full calendar years – The choice of three years strikes a balance between reducing the impact that a single year may have on the probabilistic distribution and removing old error data that may not reflect the most up-to-date status of PJM forecasting models.
 - b) Creating twenty-four probabilistic distributions based on uncertainty levels during combinations of time-of-day blocks and season – The choice of twenty-four probabilistic distributions strikes a balance between: i) quantifying the uncertainty during specific periods that are expected to have larger uncertainties (such as the morning period in winter) relative to periods that are expected to have smaller uncertainties (such as the night-time in the fall); and ii) avoiding a large number of ORDCs which may result in market outcomes that change too frequently. Since the probabilistic distributions are the basis for estimating the value of reserves, i.e., the prices in the ORDCs, the choice of twenty-four probabilistic distributions results in twenty-four ORDCs.

The seasons and time-of-day blocks that are combined to derive the twenty-four ORDCs are shown in Table 2.

Table 2: Season and Time-of-Day Blocks

Season	Time-of-Day Block (in Hour Beginning)
Summer (June – August)	1 (2300 – 0200)
Fall (September – November)	2 (0300 – 0600)
Winter (December – February)	3 (0700 – 1000)
Spring (March – May)	4 (1100 – 1400)
	5 (1500 – 1800)
	6 (1900 – 2200)

- c) Combining error data and Regulation Requirement data point-by-point to derive a net-load error probabilistic distribution – For each timestamp⁴ in the three full calendar years, the forecast error data from the individual uncertainties:
- Load, Wind Output, Solar Output, availability of thermal units for the Synchronized, and Primary Reserve Requirement
 - Load, Wind Output, Solar Output, availability of thermal units, and net interchange for the 30-minute Reserve Requirement

is combined with the Regulation Requirement data to calculate the time stamps' net-load forecast error according to the following formula:

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.

All of the terms in the above formula are expressed in megawatts. The look-ahead period for uncertainty is represented by x (30 minutes for the Synchronized and Primary Reserve Requirements, 60 minutes for the 30-minute Reserve Requirement). Note that the Net Interchange Schedule uncertainty only applies to the 30-minute Reserve Requirement. The reason it is appropriate to exclude net interchange schedule in the Net Load Error for the Synchronized and Primary Reserve Requirements is that the Net-Interchange Schedule forecast error in the applicable look-ahead interval is negligible.⁵

⁴ The net-load error calculation is made every five minutes for the Synchronized and Primary Reserve Requirement; every fifteen minutes for the 30-minute Reserve Requirement because the Net-Interchange Schedule Forecast is run every fifteen minutes.

⁵ Interchange schedules cannot be changed in the last twenty minutes before an RT SCED case. Therefore, the thirty-minute forecasted net-interchange schedule value is very close to the actual net-interchange schedule value.

- d) Using empirical distributions rather than imposing a distribution (e.g., normal)⁶ to the net-load error data – Each of the twenty-four sets of net-load error values from the most recent three full calendar years is used as the net-load error empirical probabilistic distribution. This approach does not require imposing one of the theoretical distributions (e.g., normal) on the data.
16. Using each of the above empirical probabilistic distributions of net-load error to calculate, for instance, the probability of the net-load error being greater than a certain value y , can be performed simply by counting the number of observations in the distribution that are greater than y , divided by the total number of observations in the distribution.

Value of Reserves

17. As I discuss above, establishing the value of reserves in excess of the MRR depends on calculating the probability of not meeting the MRR when said reserve levels in excess of the MRR are available given all the uncertainties and uncertainty-mitigating factors (where all the uncertainties and uncertainty-mitigating factors are quantified via the net-load error distribution). To calculate the incremental value of reserves in excess of the MRR, PJM proposes to use the concept of expected value. Expected value refers to the weighted average outcome of a given decision when all possible outcomes are considered weighted by the probability of each outcome. In the context of the ORDC, the decision is procuring reserves in excess of the MRR while the outcomes are either meeting the MRR or failing to meet the MRR. Meeting the MRR entails no penalty whereas failing to meet the MRR triggers the penalty factor. Assume PBMRR is the probability of failing to meet MRR when X reserves in excess of the MRR are available given all the uncertainties and uncertainty-mitigating factors. The Expected Value of X reserves in excess of the MRR can be expressed as:

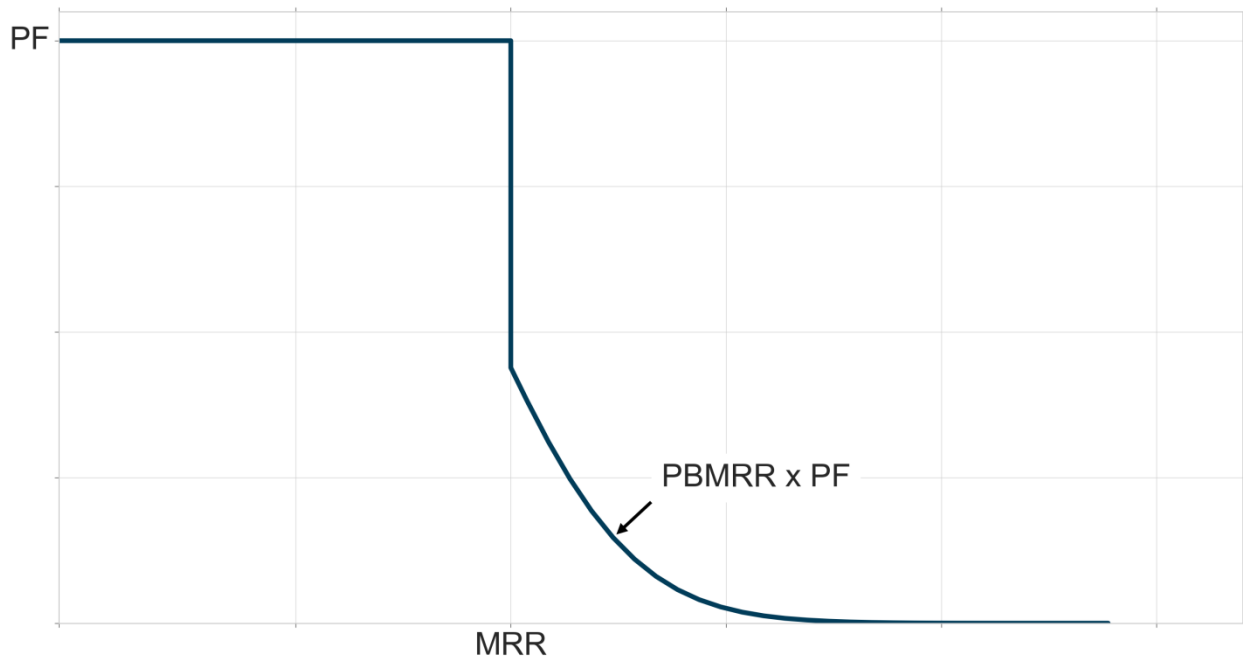
$$\begin{aligned}\text{Expected Value of } X &= \text{PBMRR}(X) \times \text{Penalty Factor} + (1 - \text{PBMRR}(X)) \times 0 \\ &= \text{PBMRR}(X) \times \text{Penalty Factor}\end{aligned}$$

18. For example, if the MRR associated with the Synchronized Reserve (SR) Requirement is 1,400 MW, then the Expected Value of 300 MW in excess of the MRR (i.e., 1,700 MW) is equal to the PBMRR of 300 MW times the penalty factor corresponding to the SR MRR. The PBMRR of 300 MW represents how often in the last three years the 30-minute net-load error in the applicable season and time-of day block combination has been greater than 300 MW. Therefore, the PBMRR calculation is performed by counting the number of observations in the applicable net-load error empirical distribution that are greater than 300 MW, divided by the total number of observations in the distribution.
19. Therefore, for reserve quantities between zero and the MRR, the incremental value is the penalty factor whereas for reserve quantities in excess of the MRR, the incremental value

⁶ As used here, “normal” refers to calculating the mean and standard deviation, and then the probabilities would be based on the theoretical normal distribution.

is calculated per the formula above. These incremental values constitute the prices in the ORDC as shown in Figure 1: if the system is short of reserves (i.e., the available reserve quantity is below the MRR) the price is the penalty factor to signal the need for more reserves in the system; as reserve quantities increase in excess of the MRR, the price gradually decreases signaling that the system has better capability to deal with the real-time uncertainties that may trigger an MRR shortage. Eventually, the prices in the ORDC drop to zero signaling that procuring additional reserves provides no incremental value due to the fact that the probability of experiencing real-time uncertainties of the same magnitude as the amount of additional reserves is zero.

Figure 1: Proposed ORDC Shape



Discussion of Selected Items in Proposed ORDC

20. The following items are discussed to provide further clarification on the underlying principles governing the shape of the proposed ORDC:
 - a) Horizontal segment between 0 and MRR on the x-axis priced at the Penalty Factor on y-axis – Applying the Expected Value of X formula above to reserve quantities below the MRR yields prices that are below the Penalty Factor. Such result is not consistent with the horizontal segment in the proposed ORDC. This occurs because the probability of failing to meet the MRR is less than one (or conversely, there is a non-zero probability that the MRR is met), even if there is an ex-ante MRR deficiency. Such a situation can be described as pricing reserves below the penalty factor when there is an MRR deficiency ex-ante because there is a non-zero chance that the net-load forecast error will turn out in PJM's favor, avoiding an MRR deficiency ex-post. Furthermore, an extreme version of the above situation where the quantity of reserves ex-ante is zero would yield an associated price that is less than the penalty factor, just because there is a slim

chance that the net-load forecast error is so large *and* in PJM's favor that the MRR is met. This is inconsistent with operating the grid securely and reliably. Hence, if the system is short of the MRR ex-ante, the corresponding price in the ORDC should escalate to signal the need for more reserves. In the proposed ORDC, the penalty factor provides that signal.

- b) Width of the curve – PJM's proposed ORDC is data-driven with the downward-sloping segment based on observed recent historical uncertainty. As such, the resulting width of the ORDC is a reflection of the following PJM-specific observations:
- i. PJM is a large system. This entails that even a small load forecast percent error (e.g., one percent) is a sizable megawatt amount relative to the MRR associated with each reserve requirement. The same observation can be made regarding forced outages of thermal units.
 - ii. Renewable (wind and solar) penetration is low relative to the total generation in the PJM system, but impactful for reserve procurement. Wind and solar resources still represent a small share of the PJM resource fleet. However, the magnitude of the uncertainty associated with forecasting the current absolute penetration levels of wind resources especially (*see infra* Wind Output columns in Table 3 and Table 4), is high relative to the MRR associated with each reserve requirement. Expected increased penetration levels are likely to increase the magnitude of the forecasting uncertainties. However, if PJM forecasting models were to become more accurate in the future, such accuracy improvements will be reflected in the ORDCs by reducing the width of the downward-sloping segment.
 - iii. Table 3 and Table 4 show the 30-minute and 60-minute mean and standard deviation of the observed forecasts' errors and forced outages of thermal units for the summer peak period (summer afternoon) and a winter peak period (winter morning) in 2015–2017. Note that the PBMRR values used in the derivation of the ORDCs depend on the entire net-load error distribution and therefore, the standard deviation is a relevant statistic (in addition to the mean) to illustrate the magnitude of the uncertainties.

Table 3: 30-minute Forecasts' Error and Force Outages during selected periods

Period	Load		Wind Output		Solar Output		Forced Outages Thermal	
	Mean	St. Dev.	Mean	St. Dev.	Mean	St. Dev.	Mean	St. Dev.
Summer - Block 5	55.1	463.9	-73.2	201.3	-32.3	34.2	132.6	230.1
Winter - Block 3	69.3	482.8	-160.6	253.1	12.5	48.8	132.6	251.0

All values in MW. Errors are calculated as Actual minus Forecast. Hence, positive Mean values indicate underforecasting while negative Mean values indicate overforecasting. Forced Outages values can only be positive.

Table 4: 60-minute Forecasts' Error and Forced Outages during selected periods

Period	Load		Wind Output		Solar Output		Forced Outages Thermal		Net-Interchange Schedule	
	Mean	St. Dev.	Mean	St. Dev.	Mean	St. Dev.	Mean	St. Dev.	Mean	St. Dev.
Summer - Block 5	75.0	787.1	-65.3	242.0	-44.5	39.1	273.8	340.1	-73.6	392.2
Winter - Block 3	153.5	808.8	-158.2	303.2	6.2	54.4	269.0	379.2	-234.7	518.3

All values in MW. Errors are calculated as Actual minus Forecast. Hence, positive Mean values indicate underforecasting while negative Mean values indicate overforecasting. Forced Outages values can only be positive. Net-Interchange equals imports minus exports.

Mathematical Formulation

21. For ease of exposition, this subsection is focused on the mathematical formulation at the regional transmission organization (“RTO”) level. Zonal considerations, which are also part of the PJM proposal, are described in the next subsection.
22. The PJM Proposal considers three reserve requirements: Synchronized (SR), Primary (PR) and 30-minute (R30). An ORDC is developed for each of these three requirements. Each of the ORDCs has a penalty factor (PF), a minimum reserve requirement (MRR) and a corresponding net-load error probabilistic distribution. The probabilistic distribution for SR and PR is based on 30-minutes uncertainty while the probabilistic distribution for the R30 ORDC is based on 60-minutes uncertainty.
23. In addition, three reserve products are defined: Synchronized (SR), Non-Synchronized (NSR), and Secondary (SecR). The relationship between the requirements and the products that can contribute to meet the requirement is shown in Table 5.

Table 5: Relationship between Requirement and Products in PJM Proposal

Requirement	Products Contributing to Requirement
Synchronized (SR)	Synchronized (SR)
Primary (PR)	Synchronized (SR) and Non-Synchronized (NSR)
30-minute (R30)	Synchronized (SR), Non-Synchronized (NSR), and Secondary (SecR)

Let,

MRR_{SR} : minimum reserve requirement in the SR ORDC

MRR_{PR} : minimum reserve requirement in the PR ORDC

MRR_{R30} : minimum reserve requirement in the 30-minute Reserves ORDC

PF_{SR} : penalty factor in the SR ORDC

PF_{PR} : penalty factor in the PR ORDC

PF_{R30} : penalty factor in the 30-minute Reserves ORDC

$PBMRR_{30}$: probability of failing to meet the MRR using 30 minutes uncertainty; this probability is applicable to the SR and PR ORDCs.

$PBMRR_{60}$: probability of failing to meet the MRR using 60 minutes uncertainty; this probability is applicable to the R30 ORDC.

r_{SR} : quantity of SR Product contributing to meet the SR, PR, and R30 requirements

r_{NSR} : quantity of NSR Product contributing to meet the PR and R30 requirements

r_{SecR} : quantity of SecR Product contributing to meet the R30 requirement

The shadow prices (SP) that result from using the ORDCs in the co-optimization of energy and reserves can be written as:

$$\begin{aligned}
 SP_{SR}(r_{SR}) &= \begin{cases} PF_{SR} PBMRR_{30}(r_{SR} - MRR_{SR}), & r_{SR} - MRR_{SR} \geq 0 \\ PF_{SR}, & r_{SR} - MRR_{SR} < 0 \end{cases} \\
 SP_{PR}(r_{SR}, r_{NSR}) &= \begin{cases} PF_{PR} PBMRR_{30}(r_{SR} + r_{NSR} - MRR_{PR}), & r_{SR} + r_{NSR} - MRR_{PR} \geq 0 \\ PF_{PR}, & r_{SR} + r_{NSR} - MRR_{PR} < 0 \end{cases} \\
 SP_{R30}(r_{SR}, r_{NSR}, r_{SecR}) &= \begin{cases} PF_{R30} PBMRR_{60}(r_{SR} + r_{NSR} + r_{SecR} - MRR_{R30}), & r_{SR} + r_{NSR} + r_{SecR} - MRR_{R30} \geq 0 \\ PF_{R30}, & r_{SR} + r_{NSR} + r_{SecR} - MRR_{R30} < 0 \end{cases}
 \end{aligned}$$

The MCP at the RTO level for each of the reserve products are a function of the above shadow prices, recognizing the contribution of the product to each of the requirements:

$$SRMCP = SP_{SR}(r_{SR}) + SP_{PR}(r_{SR}, r_{NSR}) + SP_{R30}(r_{SR}, r_{NSR}, r_{SecR})$$

$$NSRMCP = SP_{PR}(r_{SR}, r_{NSR}) + SP_{R30}(r_{SR}, r_{NSR}, r_{SecR})$$

$$SecRMCP = SP_{R30}(r_{SR}, r_{NSR}, r_{SecR})$$

24. The above MCPs are representative of a cascading model for probabilities and prices: the Synchronized Reserve Market Clearing Price (“SRMCP”) reflects the contribution that SR resources make to satisfy the SR, PR, and R30 requirements. Similarly, the Non-Synchronized Reserve Market Clearing Price (“NSRMCP”) reflects the contribution that NSR resources make to satisfy the PR and R30 requirements. Finally, the Secondary Reserve Market Clearing Price (“SecRMCP”) reflects the contribution that SecR resources make to satisfy the R30 requirement.

Zonal ORDC Considerations

25. The PJM proposal considers the development of zonal ORDCs. And while no tariff revisions are necessary to accommodate this proposal, PJM has included a discussion of it in this filing for completeness. The methodology to develop the zonal ORDCs includes the aspects so far described in this affidavit including the following clarifications:
- a) If the zone is a transmission zone or a group of transmission zones, actual load, wind output, solar output, and availability of thermal unit uncertainties are used to develop the net-load error probabilistic distribution. A zonal estimate of the net interchange schedule uncertainty (which only applies to the development of the 30-minute Reserves ORDC) and of the Regulation Requirement are also used to develop the net-load error probabilistic distribution based on the zone's average load share contribution in the most recent three calendar years to the RTO average load in each of the twenty-four combinations of season and time-of-day blocks.
 - b) If the zone is a portion of a transmission zone or a portion of multiple transmission zones, zonal estimates of the load, wind output, solar output, availability of thermal units, and net-interchange schedule uncertainties as well as of the Regulation Requirement are used to develop the net-load error probabilistic distribution. The zonal estimates are based on the zone's average load share contribution in the most recent three calendar years to the encompassing transmission zone(s)' average load (for load, wind output, solar output, and availability of thermal units uncertainties) and RTO average load (for the net interchange schedule uncertainty and regulation requirement) in each of the twenty-four combinations of season and time-of-day blocks.
 - c) The MCPs at the zonal level for each of the reserve products are a function of the shadow prices resulting from using the zonal ORDCs in the co-optimization of energy and reserves, recognizing the contribution of the product to meet not only each of the zonal requirements but also the RTO requirements.
26. This concludes my affidavit.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

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Docket No. ER19-__-000

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PJM Interconnection, L.L.C.

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Docket No. EL19-__-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 "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 27th day of March, 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