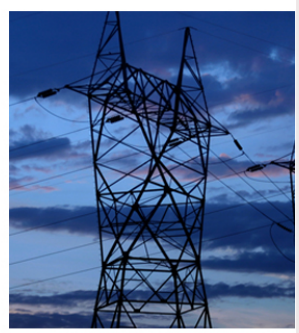
Price Formation in Organized Wholesale Electricity Markets

Docket No. AD14-14-000

Staff Analysis of Shortage Pricing in RTO and ISO Markets

October 2014





FEDERAL ENERGY REGULATORY COMMISSION

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I. Executive Summary

This paper is part of an effort to evaluate matters affecting price formation in the energy and ancillary services markets operated by Regional Transmission Operators (RTOs) and Independent System Operators (ISOs) subject to the jurisdiction of the Federal Energy Regulatory Commission (Commission). It focuses on shortage pricing in the RTOs and ISOs and the tariff provisions governing what defines a shortage and when shortage pricing is invoked, the interaction of shortage pricing for different energy and operating reserve products, and the RTOs' and ISOs' experiences with reserve deficiencies and shortage pricing.

Locational marginal prices for energy and ancillary services ideally would reflect the true marginal cost of production, taking into account all physical system constraints, and fully compensate all resources for the variable cost of providing service.[1] If demand were fully price responsive and shortage pricing rules accurately reflected the value of avoiding involuntary load curtailments, short-run energy prices would provide both an accurate price signal for short-term supply and demand behavior and facilitate long-term entry and exit. To that end, Commission-jurisdictional RTO and ISO markets are built on a foundation that encourages resources to offer at a price consistent with marginal cost.[2] When the system operator is unable to meet system needs, it applies 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. Ideally, these prices would reflect the valuation consumers place on avoiding an involuntary load curtailment. Under such conditions, prices should rise, inducing performance of existing supply resources and encouraging load to reduce consumption so that the system operator would not need to administratively curtail load to maintain reliability. 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.

Understanding the mechanisms of shortage pricing and the RTOs' and ISOs' experiences with shortages and shortage pricing may help to shed light on markets, operations and the efficiency of existing market rules related to shortage pricing. Commission staff's preliminary observations suggest the following.

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[1] *See Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice, Docket No. AD14-14-000 (June 19, 2014).

[2] Commission staff is issuing a staff report on market power mitigation rules contemporaneous with this paper.

- RTOs and ISOs all tend to define a shortage in the same way, but shortage pricing triggers differ.
- Shortage events are rare, sometimes not occurring at all in a year. But the frequency at which these events occur varies by RTO or ISO.
- Oftentimes, shortage events only last for a matter of a few 5-minute dispatch intervals.
- Because shortage events are rare and short-lived, potential revenue to be earned from shortage pricing could be minimal.
- Some operator actions taken to avert a shortage are not reflected in market-clearing prices.
- Because of the lag between price signals and import and export scheduling, it can be difficult for market participants to efficiently schedule exports and imports to respond to shortage conditions, sometimes leading to inefficient behavior.

This paper is intended to spur discussion and lead to a more comprehensive understanding of the drivers and market impacts of shortage events and shortage pricing. The conference scheduled for October 28, 2014, will provide an opportunity for the Commission staff to learn the views of market participants, RTOs and ISOs, and market monitors.

II. Introduction

In an effort to better understand how shortage, or scarcity, pricing[3] works in the organized RTO and ISO markets, this paper outlines the tariff rules and operating procedures of the RTOs and ISOs, describes how shortages or emergencies are defined and what impact this may have on prices for energy and operating reserves. Commission staff reviewed the tariffs and recent experiences for the wholesale markets of California Independent System Operator Corporation (CAISO), ISO New England Inc. (ISO-NE), Midcontinent Independent System Operator, Inc. (MISO), New York Independent System Operator, Inc. (NYISO), PJM Interconnection, L.L.C. (PJM), and Southwest Power Pool, Inc. (SPP).[4] This paper is organized around two main topics: the goals of shortage pricing and the key design considerations that impact shortage pricing.

[3] In general, this report is focused on pricing rules when an RTO or ISO experiences (or nears) a deficiency in one of the ancillary service products or involuntarily curtails load. The terms “shortage pricing” and “scarcity pricing” are often, though not always, used synonymously to refer to these pricing events. In the case where an RTO or ISO uses these terms to mean different things, we note that and use the terms as defined for that RTO or ISO.

[4] While the details of SPP’s shortage pricing tariff provisions are provided in Appendix 6, further analysis of SPP’s experiences is not included in this report because its day-ahead market was not launched until 2014.

This paper does not attempt to assess whether existing shortage pricing rules are "correct" or are otherwise ripe for change. Rather, the analysis presented here is intended to facilitate discussions concerning the matter of shortage pricing as it affects price formation in the RTO and ISO energy and ancillary services markets.

In Section III, Commission staff describe the goals of shortage pricing and explain how shortage pricing affects price formation and why such a pricing method is needed. In Section IV, Commission staff present some of the important design decisions that go into establishing and implementing shortage pricing. To better illustrate these design choices and their impacts, actual RTO and ISO shortage pricing events over recent years are discussed in Section V. In order to empirically assess actual events, data were taken from the RTOs' and ISOs' publicly available websites, Ventyx data reporting,[5] and RTO and ISO data submissions pursuant to Order No. 760.[6] Section VI offers concluding remarks and identifies issues for future discussion. A detailed description of each RTO's and ISO's definition of a shortage and what triggers shortage pricing, and the actions that can or must be taken to avert a shortage are found in the appendices.

III. Shortage Pricing

A. What is Shortage Pricing

An RTO or ISO procures, on behalf of its market participants, energy and operating reserves in daily and hourly wholesale markets.[7] It must procure sufficient resources to meet the expected load at any given moment in time and sufficient operating reserves to provide for the flexibility needed to maintain reliability from moment-to-moment and to meet unexpected challenges. A resource bidding into the wholesale market may offer to supply energy and/or one or more operating reserve products. The RTO or ISO will

[5] Ventyx, *Velocity Suite On-line*, *available at* https://velocitysuite.ventyx.com.

[6] *Enhancement of Electricity Market Surveillance and Analysis Through Ongoing Electronic Delivery from Regional Transmission Organizations and Independent System Operators*, Order No. 760, FERC Stats. & Regs. ¶ 31,330 (2012). In Order No. 760, the Commission stated that it may make publicly available staff white papers, among other things, that contain analyses derived from data that the Commission uses. *Id.* P 35.

[7] "Operating reserves" is the term used in this paper to refer to the ancillary services procured in the wholesale market. All RTOs and ISOs use slightly different names for these products and/or define the reserve products in slightly different ways. Typically, operating reserves includes: (a) Regulating Reserve, used to account for very short-term deviations between supply and demand (e.g. 4 to 6 seconds); (b) Spinning, or Synchronous Reserve, which is capacity held in reserve and synchronized to the grid and able to respond within a relatively short amount of time (e.g., within 10 minutes), to be used in case of a contingency, such as the loss of a generator; and, (c) Non-Spinning Reserve, capacity that is not synchronized to the grid and which can take longer to respond (e.g., within 10-30 minutes) in case of a contingency. Collectively, these and other ancillary services help maintain system frequency, maintain a close balance between the supply and demand of electricity, and ensure continuous delivery of energy when unexpected events remove a resource from the grid.

evaluate all bids to find the most efficient mix of resources to meet all of the system's needs and set market prices for each product. These market prices are co-optimized so that the lowest system costs are incurred overall; such that the market price for energy and each operating reserve product are interrelated.[8] Many of the supply resources available to the system operator may be dispatched in real time to provide some combination of energy and operating reserve products simultaneously.

When energy and operating reserves necessary to maintain reliability are in short supply, one would expect to see higher prices. This is for several reasons. First, the variable cost of the most expensive resource available and needed to serve load during periods of system stress is likely to be much higher than the variable cost of the last unit needed in more moderate system conditions. Second, various studies suggest that consumers place a very high value on avoiding involuntary curtailments.[9] However, price formation under tight market conditions is not a straightforward process. The vast majority of demand is not price responsive and thus provides no price signal regarding its willingness to stop consuming. In addition, operators appropriately take some out-of-market actions to avoid shortage conditions. Shortage pricing is the method RTOs and ISOs employ to more accurately price energy and operating reserves when market conditions are tight.

These more accurate prices are intended to achieve two primary goals. The first goal is to send a short-term price signal to incent performance of existing resources and help to maintain reliability. In the short term, these prices should be high enough to induce existing resources (including imports) to be available to the market to the maximum extent possible and signal consumers to reduce demand. Therefore, shortage pricing ought to reflect consumers' valuation of energy.

The second goal of shortage pricing is to facilitate long-term economic entry through the construction of new supply resources and exit of resources that are no longer economic. This is especially important in RTOs or ISOs where there is no centralized capacity

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[8] Typically, a resource will be eligible for an opportunity cost payment when it provides an ancillary service that prevents it from providing and being paid the market price for energy. This is done so that the resource will be revenue neutral towards the system operator's decision as to which service the resource will provide. Otherwise, a resource may not be willing to provide a service, such as Spinning Reserves, that would earn less than if that resource had sold energy into the wholesale market.

[9] *See* London Economics International, Inc., *Estimating the Value of Lost Load* (June 17, 2013), *available at* http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf); Eimear Leahy and Richard S.J. Tol, *An Estimate of the Value of Lost Load for Ireland* (Oct. 2010), *available at* http://www.researchgate.net/publication/227355786_An_estimate_of_the_value_of_lost_load_for_Ireland/links/0912f50d1950cdb606000000; Adriaan van der Welle and Bob van der Zwaan, *An Overview of Selected Studies on the Value of Lost Load* (Nov. 15, 2007), *available at* http://www.transust.org/workplan/papers/wp2_task_5_lost_load.pdf.

market or other mechanism to ensure resource adequacy, but it is also important in regions with a capacity market or other mechanism to ensure resource adequacy. When shortage prices accurately reflect consumers' valuation of energy, operating reserves, and planning reserves, the resulting long-run participation (entry and exit) will be economically efficient because revenues (including shortage pricing) will just cover a resource's long-run revenue requirements.[10] To the extent stakeholders want a higher level of resource adequacy than an energy-only market can produce, a capacity market construct can be added to the energy market with appropriate shortage pricing to induce the necessary new entry.[11]

While every RTO and ISO tends to broadly define a shortage in the same way, which is the inability to meet the minimum requirements for operating reserves and/or energy, there are many more technical differences in how each RTO and ISO implements shortage pricing. This paper explores some of the different market design approaches.

B. How Shortage Pricing Works[12]

At a high level, shortage pricing is part of the system of marginal cost pricing. Under efficient pricing, prices reflect the marginal costs of delivering the product to the customer. When the supply of capacity exceeds demand for energy and operating reserves, the marginal cost of energy reflects the marginal out-of-pocket costs of the marginal generator – primarily fuel costs. The marginal cost of providing operating reserves is principally opportunity costs – the net revenue that the resource could have received by selling energy instead of providing reserves. However, when the amount of physically available supply of capacity is less than that needed (at the price desired) to meet energy demand and operating reserve requirements, additional energy demand can be met only by reducing the amount of operating reserves. The marginal cost of energy then includes the opportunity cost associated with reducing operating reserves.[13] Ideally, during shortages, the price of operating reserves would reflect this opportunity cost, and the price of energy would reflect this opportunity cost in addition to the marginal out-of-pocket cost of producing energy.

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[10] *See* The Brattle Group and Astrape Consulting, *Resource Adequacy Requirements: Reliability and Economic Implications* at 74 (Sept. 2013), *available at* http://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf.

[11] *Id.* at 83-84.

[12] The following discussion does not describe any specific shortage pricing program and is not meant to reflect how a shortage pricing program should be designed. Instead, this section is intended to generally introduce some of the design elements that are typically addressed when implementing such a program.

[13] That is, by reducing operating reserves, the probability increases that load will be involuntarily curtailed if a contingency occurs. The resulting associated expected cost is the probability of an involuntary load curtailment multiplied by the value of the lost load.

Shortage pricing is implemented through a series of design elements, discussed more fully in Section IV, that ideally reflect the goals of shortage pricing, the philosophical foundation for shortage pricing and the operational realities of employing shortage pricing regimes.

Shortage Triggers - Physical Shortage vs. Price-cap Induced Shortage

In practice, shortage pricing is triggered under two general scenarios. The first occurs when the system operator simply does not have enough resources available to meet energy and operating reserve requirements. In this case, attempting to find a least-cost dispatch of resources subject to a simple constraint that requires an exact amount of energy and operating reserves to be procured would result in an unsolvable problem. Under the second scenario, the RTO or ISO establishes a price above which it will choose to be deficient of operating reserves rather than procure resources that may be available to meet the minimum requirement, but cost more than the established price. This construct establishes a trade-off between reliability and cost. Under either scenario, prices are established through the use of administratively-determined prices or "penalty factors," rather than actual resource supply offers.[14]

Depending on the penalty prices and physical supply offers, these penalty factors may result in market-clearing prices either increasing to a shortage price higher than the last available offer or being capped at the penalty factor. When supply is physically short, the result is an administratively-determined shortage price that is higher than the most expensive supply offer cleared in the wholesale market. This shortage price reflects the cost of the system not being able to meet energy and minimum operating reserve requirements. However, when supply is available but more expensive than the penalty price, prices are set at the penalty price rather than at the more expensive resources' offers. In this instance, the shortage price caps the maximum price the system will pay to meet energy and reserve requirements and chooses to operate with fewer operating reserves than to rely on resources more costly than the shortage price.

Conceptually, the penalty factor can be thought of as a "pseudo" or "virtual" resource that is offering supply of energy and operating reserves at a specific price.[15] The system operator "commits" this pseudo resource for the remaining amount of the reserve requirement (though it is not physically present, of course).

Cumulative Effect of Shortages of Multiple Services

[14] Similar penalty factors can also apply when there are transmission constraints that impact redispatch. These penalties impact market prices in a similar fashion but are not addressed in this paper.

[15] PJM, *Shortage Pricing Refresher Training* at 10 (May 23, 2013), *available at* http://www.pjm.com/~/media/committees-groups/committees/mrc/20130523-sp/20130523-shortage-pricing-refresher-training.ashx.

Typically, 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. A shortage can impact all operating reserves, a combination of operating reserves, or just one operating reserve, or a shortage can be a depletion of all operating reserves and an inability to serve energy demand. And, in most RTOs and ISOs, a shortage can occur on a region-wide basis or on a zonal-basis. Additionally, penalty factors may be additive in instances where both system and local requirements exist.

Shortage pricing typically involves price formation during deficiencies for three operating reserve products: (a) Regulating Reserve, used to account for very short-term deviations between supply and demand (e.g., 4 to 6 seconds); (b) Spinning, or Synchronous Reserve, which is capacity held in reserve and synchronized to the grid and able to respond within a relatively short amount of time (e.g., within 10 minutes), to be used in case of a contingency, such as the loss of a generator; and, (c) Non-Spinning Reserve, capacity that is not synchronized to the grid and which can take longer to respond (e.g., within 10-30 minutes) in case of a contingency.[16]

Because qualification to provide different reserve products requires different operating characteristics, resources providing one operating reserve product cannot always provide another service. For example, because Regulating Reserve is actively producing energy at a moment in time and can respond to an Automatic Generation Control signal within 4 or 6 seconds, to the extent an ISO or RTO has extra Regulating Reserve, these resources can always substitute for Spinning and Non-Spinning Reserve. However, Spinning and Non-Spinning Reserves cannot necessarily substitute for Regulating Reserve. To the extent an RTO or ISO can choose to be deficient of a reserve service, most choose to become deficient of the lowest quality service (e.g., Non-Spinning Reserve) first. To illustrate, assume the Regulation Reserve minimum requirement is 10 MW and the Spinning Reserve minimum requirement is 20 MW. The entire 10 MW minimum requirement for Regulation Reserve must be met by regulation-qualified resources. However, the Spinning Reserve requirement can be met by an additional 20 MW of resources also able to provide Regulation Reserve. This substitution happens any time the next MW of a regulation-qualified resource (beyond the 10 MW minimum) is cheaper than the next MW of spin-qualified resource (that is not also regulation-qualified).

The ability to substitute a resource offering a higher quality reserve service to provide a lower quality reserve service creates the opportunity cost described above. Thus, the shortage price for regulation service, for example, could reflect this substitutability. Suppose the penalty factor for being short of Regulation Reserve is $10/MW and the

[16] All RTOs and ISOs use slightly different names for these products and/or define the reserve products in slightly different ways.

penalty factor for being short of Spinning Reserve is $5/MW, and the system operator is short of meeting both regulation and Spinning Reserve requirements. In this case, an additional MW of regulation capacity could be used to meet either the regulation or Spinning Reserve requirement. Therefore, the regulation shortage price could reflect this substitutability by setting the regulation clearing price equal to the combined penalty price of $15/MW and setting the Spinning Reserve clearing price equal to $5/MW. The particular order in which an RTO or ISO allows a deficiency to occur will dictate the specific way in which the shortage prices are added together.

Similar to the substitutability of operating reserves, penalty factors may be added to reflect the violation of system and local requirements ("nested" requirements). If, for example, a market is short of meeting both a system and local requirement for Spinning Reserve, the local shortage price may reflect the penalty price of failing to meet both requirements because additional capability within the local area could satisfy both the local and system requirement. That is, the opportunity cost of being deficient of a reserve service within a local area includes the cost of being deficient on a system-wide basis.

In addition to the substitutability of certain operating reserves, the price formation process also involves setting an energy price that maintains appropriate incentive to provide either energy or operating reserves. Energy prices are set such that any resource dispatched to provide energy will be indifferent between providing energy or operating reserves. If, for example, the system operator needs to dispatch a resource that is providing Spinning Reserve to instead provide energy, and as a result the system becomes deficient of Spinning Reserves, the price of energy will include the opportunity cost of this unit not providing Spinning Reserve.[17] This opportunity cost can be reflected in the energy price by adding the penalty price of not meeting the Spinning Reserve requirement to the marginal cost of the generator.

IV. Elements of Shortage Pricing Programs

A. Administrative Shortage Prices

The effectiveness of any shortage pricing program in meeting the goals discussed above will to some extent depend on the market clearing prices during shortage events. If shortage prices are too high, market participants may face charges in excess of the value of avoiding an involuntary load curtailment. If shortage prices are too low, the prices may fail to elicit an appropriate market response to address the reliability issue at hand or

[17] It is possible that capacity used to provide energy could not have been used to provide operating reserves due to ramp rate requirements. In CAISO, for example, a generator receiving an award for Spinning Reserves must be able to ramp to its awarded quantity in 10 minutes.

facilitate efficient entry and exit by adequately contributing to fixed-cost recovery.[18] Each RTO and ISO establishes very different prices during shortage events.

There are generally three ways that RTOs and ISOs establish prices during shortage conditions. One is to set the price to which a market-clearing price moves whenever, and to whatever degree, the system operator is unable or unwilling to procure the needed reserve product to meet the requirement. The second is to use a schedule that defines how the market-clearing price increases as the shortage worsens, in combination with certain administratively-determined parameters. The third is some combination of the prior two.

The following discussion identifies some of these differences and in some cases mentions how RTOs and ISOs have changed some of the prices used in their shortage pricing programs.[19] The discussion focuses on both the way prices are set (fixed price vs. prices varying by the severity of the shortage) and the general level of the resulting shortage prices. This paper does not address whether shortage prices are too low or too high but rather highlights the differences in practice to set the stage for further discussions.

ISO-NE, PJM, and SPP use fixed, individual shortage price levels, rather than a schedule of prices to establish shortage prices. ISO-NE's shortage pricing is shown in Table 1, PJM's in Table 2, and SPP's in Table 3.[20] In ISO-NE for example, if the system operator does not meet the requirement for Local Thirty-Minute Operating Reserve, the market-clearing price (MCP) for that product will be set at $250/MW, as defined by the Reserve Constraint Penalty Factor. PJM's and SPP's rules work in a similar fashion.

[18] As noted above, entry and exit decisions are the result of both energy and operating reserve market outcomes, as well as compensation available from capacity markets or other resource adequacy constructs. In the context of shortage pricing as an aspect of price formation, the concern is simply whether scarcity pricing is playing the appropriate role in conjunction with other energy, operating reserve and resource adequacy compensation.

[19] Although it is not Commission-jurisdictional, a description of Electric Reliability Council of Texas's shortage pricing rules and experiences is included in Appendix 7 for comparison.

[20] In each of these tables, the operating reserve products are presented in order from least-valuable to most-valuable.

Table 1. ISO-NE Reserve Constraint Penalty Factors[21]

Requirement	Price/MW
Local Thirty-Minute Operating Reserve	$250
System Thirty-Minute Operating Reserve	$500
System Ten-Minute Non-Spinning Reserve	$850
System Ten-Minute Spinning Reserve	$50
Replacement Reserve[22]	$250

Table 2. PJM Shortage Pricing

Product Shortage	Price/Penalty Factor
Non-Synchronous Reserve	$550/MWh
Synchronous Reserve[23]	$550/MWh
Regulation	n/a

[21] ISO-NE also has penalty factors for Regulating Reserve. The Regulation Capacity penalty factor ($/MW) can be set in two ways: (a) if the energy component of the real-time locational marginal price is greater than or equal to $100/MWh, the penalty factor is $100/MW plus the energy component of the real-time locational marginal price for each megawatt of Regulation Capacity shortfall, and (b) if the energy component of the real-time locational marginal price is less than $100/MWh, the penalty factor is the maximum of either zero or $100 plus the energy component of the real-time locational marginal price (i.e. the penalty factor cannot be negative) for each megawatt of Regulation Capacity shortfall. Regulation mileage penalty factor is $10/MW for each megawatt of Regulation Service shortfall; in addition, selection will consider opportunity cost sensitivities associated with large changes in the estimated opportunity cost of a Resource due to the shape of the resource's supply offer price curve. *See* ISO-NE, Market Rule 1, § III.14.5.

[22] ISO-NE's Replacement Reserve requirement is intended to help resolve conditions where additional commitments are necessary to protect the system against normal system uncertainties and to avoid the need for emergency actions due to events such as load forecast errors, generator contingencies and reductions, and resource unavailability. ISO-NE will redispatch the system, but will not take emergency actions, to maintain Replacement Reserve. The $250/MWh reserve constraint penalty factor establishes a cap on the re-dispatch cost ISO-NE will incur to maintain the Replacement Reserve requirement.

[23] PJM's penalty factor for Synchronous Reserve will increase to $850/MWh in the 2015/2016 delivery year.

Table 3. SPP System-Wide Shortage Pricing[24]

Requirement	Market-Clearing Price or Locational Marginal Price
Supplemental Reserve	$1100 + Zonal Regulation-Up plus Contingency Reserve Shadow Price[25]
Spinning Reserve	$200 + Supplemental Reserve MCP + Zonal Regulation-Up plus Contingency Reserve Shadow Price
Regulation-Up Reserve	$600 + Spinning Reserve MCP + Zonal Regulation-Up Shadow Price
Regulation-Down Reserve	$600
Energy	LMP accounts for all Shortage-Priced MCPs with a maximum = $50,000.

Shortage prices in CAISO present an example of both stepped and fixed price methods. Table 4 shows the levels to which prices rise when CAISO fails to meet any of its minimum requirements for reserves. For CAISO, in the cases of Regulation-Up and Spinning Reserve, a flat price is established no matter the degree of shortage. However, for Regulation-Down and Non-Spinning Reserve, the market-clearing price depends on the degree of shortage and increases as the shortage worsens.

Table 4. CAISO Shortage Pricing

Reserve Product	Shadow Price Impact of Shortage
Non-Spinning Reserve	
Shortage > 210 MW	$700
210 MW > Shortage > 70 MW	$600
70 MW > Shortage	$500
Spinning Reserve	$100
Regulation-Up	$200
Maximum Upward Sum	$1000 ($700+$100+$200)
Regulation Down	
Shortage > 84 MW	$700
84 MW> Shortage > 32 MW	$600
32 MW > Shortage	$500

[24] SPP's zonal shortage pricing operates in a similar manner. These details can be found in Appendix 6.

[25] A "shadow price" is the incremental cost of meeting the constraint if the constraint is relaxed by one unit. In this case, for example, if the minimum requirement for the Regulation-Up plus Contingency Reserves was increased by one MW, the shadow price would be the cost of the next MW needed to meet the new constraint level.

As is shown in Table 5, MISO presents a case of fixed, individual prices, sloped and stepped curves. MISO's pricing for Spinning and Regulating Reserves is an example of a "sloped" schedule. If MISO is unable to meet its system-wide requirement for Spinning and Regulating Reserves,[26] it will set market clearing price at a minimum of $65/MWh, and, as the shortage worsens, the market clearing price rises to a maximum of $98/MWh. However, for the same zonal requirement, MISO uses a "stepped" schedule. The market clearing price is equal to $65/MWh so long as at least 90 percent of the requirement is met. If less than 90 percent is met, the market clearing price increases to $98/MWh. MISO uses a fixed price for energy deficiencies; if MISO is unable to meet demand for energy (the most severe shortage situation) the locational marginal price (LMP) for energy is set at the Value of Lost Load, which MISO currently sets at $3500/MWh.

[26] MISO, as system operator, procures four products: Energy, Regulating Reserve, Spinning Reserve, and Supplemental Reserve. Regulating, Spinning, and Supplemental Reserves are known, cumulatively, as Operating Reserve, while Spinning and Supplemental Reserve are referred to collectively as Contingency Reserve.

Table 5. MISO Shortage Pricing

Product Shortage	Price
MISO-wide Operating Reserves	Min. $200/MWh to Max. VOLL ($3500/MWh) minus Regulating Reserve demand curve value, depending on level of shortage.
MISO-wide Spinning and Regulating Reserves	Min. $65/MWh to Max. $98/MWh depending on level of shortage.
MISO-wide Regulating Reserve	Max. of (i) Contingency Reserve Offer Cap and (ii) Peaker Commitment Cost for one hour.
MISO-wide Energy	LMP set to Value of Lost Load ($3500/MWh).
Reserve Zone Operating Reserves	Min. $200/MWh to Max. VOLL ($3500/MWh) minus maximum Regulating Reserve Demand Curve Scarcity Price.
Reserve Zone Spinning and Regulating Reserves	$65/MWh if > 90% of requirement. $98/MWh if < 90% of requirement.
Reserve Zone Regulating Reserve	Max. of (i) Contingency Reserve Offer Cap and (ii) Peaker Commitment Cost for one hour.

From the tables above, one can see that shortage prices for the same product are set at different levels in different RTOs and ISOs. While these prices, in theory, ought to reflect the value that consumers place on reliability, in reality prices oftentimes reflect a combination of this, negotiations between different stakeholders, and the experience of the system operator, as illustrated by the fact that the RTOs and ISOs change their pricing and penalty factors occasionally.

These competing interests likely explain the different price levels for similar products seen in the tables above. For instance, Synchronous Reserve in PJM, Spinning Reserve in SPP, Ten-Minute Spinning Reserve in ISO-NE, and MISO's Spinning and Regulating Reserves constraint all apply to roughly the same product. In PJM, during a shortage of Synchronous Reserve, Synchronous Reserve would be priced at $550/MWh and energy would be $550/MWh plus the relevant locational marginal energy price. In SPP, during a Spinning Reserve deficiency, Spinning Reserve would be priced at $200/MW, plus the clearing price for Supplemental Reserve, plus the zonal Regulation-Up plus Contingency Reserve shadow price. In ISO-NE, during a shortage of Ten-Minute Spinning Reserve, Ten-Minute Spinning Reserve would be priced at $50/MWh plus the price of Ten-Minute Non-Spinning Reserve, plus the price of Thirty-Minute Operating Reserve. And in MISO, if there is a deficiency in the Spinning and Regulating Reserves requirement, the market-clearing price for Spinning Reserve will be set at a level dependent upon the degree of shortage (between $65/MWh and $98/MWh) plus the price of Supplemental Reserve (derived from the Operating Reserve requirement). Depending on the levels of the prices for the other products, these price levels may be quite different.

Since ISO-NE implemented its ancillary services market design in October 2006, it has raised the Reserve Constraint Penalty Factors (i.e., the shortage prices associate with deficiencies for specific reserve products) for both the Local Thirty-Minute Operating Reserve requirement and the System Thirty-Minute Operating Reserve requirement. The Reserve Constraint Penalty Factor for the Local Thirty-Minute Operating Reserve requirement was raised from $50/MWh to $250/MWh on January 1, 2010 and from $100/MWh to $500/MWh on June 1, 2012 for System Thirty-Minute Operating Reserve. Prior to the increase in the System Thirty-Minute Operating Reserve Reserve Constraint Penalty Factor, there were a significant number of instances when ISO-NE was deficient of operating reserves even though there were sufficient physical resources available to meet the requirement. Those resources were deemed uneconomic because they could not provide reserves at a cost below $100/MWh.[27] Previous to this increase, ISO-NE would have failed to meet the operating reserves requirement in those instances when the $100/MWh cap was a binding constraint.[28] ISO-NE's External Market Monitor calculated that after ISO-NE raised this Reserve Constraint Penalty Factor to $500/MWh, System Thirty-Minute Operating Reserve clearing prices exceeded $100/MWh in 0.8 percent of the intervals during the rest of 2012, averaging roughly $174/MWh in these intervals. This increase in System Thirty-Minute Operating Reserve clearing prices illustrates the degree to which reserve prices may have been capped as a result of shortage pricing rules. The External Market Monitor also noted that reserve prices rose in the second half of 2012 to reflect the additional value of reserves as ISO-NE implemented additional changes in its reserves markets, including procuring and pricing Replacement Reserves and procuring additional Ten-Minute (and Total Operating) Reserve above the North American Electric Reliability Corporation minimum requirement.[29]

In August 2010, MISO instituted a new modeling method that reduced the frequency with which the Spinning Reserve requirement was relaxed. Prior to this change, prices varied widely and the MISO Independent Market Monitor reported that many of the largest shortages resulted in the lowest prices, with the largest shortage (630 MW) priced at just $14/MW. After the modeling change, prices were regularly more consistent with MISO's administrative shortage prices and showed, according to the MISO Independent

[27] Between January 2010 and May 2012, ISO-NE was short of total Operating Reserves an average of 17.7 hours annually. ISO-NE estimated through simulations that it would have only been short of total Operating Reserves an average of 3.5 hours annually if the Reserve Constraint Penalty Factor had been $500/MWh rather than $100/MWh. *See* ISO-NE, Memorandum from Market Development, to NEPOOL Market Participants, *Operating Reserve Deficiency Information – Historical Data – Updated* at 3 (May 16, 2014), *available at* http://www.iso-ne.com/markets/othrmkts_data/fcm/doc/opr_reserve_deficiency_info_hist_data_updated_5_21_2014.zip.

[28] Potomac Economics, *2012 Assessment of The ISO-New England Electricity Markets* at 31, Figure 9, (May 2013), *available at* http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2012_emm_rprt_final.pdf.

[29] *Id.* at 32.

Market Monitor, that the improved modeling method had resulted in reduced price suppression.[30]

On May 1, 2012, MISO implemented a new two-step demand curve for Spinning Reserve. Shortage quantities of less than 10 percent of the reserve requirement are priced at $65/MWh, while those exceeding 10 percent are priced at $98/MWh. According to the Independent Market Monitor, this resulted in more efficient pricing, because MISO no longer relaxed the Spinning Reserve requirement to set prices during shortage as often. Prior to this, MISO would relax the Spinning Reserve requirement rather than pay a higher penalty price for being short of the reserve requirement.

B. Defining Reserve Zones

The RTOs and ISOs all include sub-zones inside their overall footprints for which there are minimum reserve requirements as well. Shortage pricing can also be triggered in just a reserve zone and these can sometimes be additive, depending upon where a shortage occurs. For example, in NYISO, if a shortage occurs in the New York Control Area, the shortage price is set as indicated in the New York Control Area column, shown in Table 6. Similarly, if the shortage occurs in just the East of Central East area or just the Long Island area, the market clearing price is set as indicated in the East of Central East column or the Long Island column, respectively. However, prices in each subzone will also reflect the shortage price in larger zones. For example, prices in the East of Central East area, which is nested within the New York Control Area zone, will also reflect shortage prices in the New York Control Area.[31] In addition, the values are additive for products that can substitute for each other. For example, if the New York Control Area is short of both Thirty-Minute and Ten-Minute Reserve, that would result in shortage prices in the New York Control Area for Ten-Minute Reserve of at least $500/MWh (short 200 MW or less of Thirty-Minute Reserve) and up to $650 (short more than 400 MW of Thirty-Minute Reserve).

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[30] Potomac Economics, *2010 State of the Market Report for the Midwest ISO* at 58 (June 2011), *available at* http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2010_immu_rpt_drft_final_june_11.pdf.

[31] For example, if there is a shortage of Ten-Minute Reserves in Long Island and East of Central East, but not the New York Control Area, Ten-Minute Reserves will be priced at $525/MWh in Long Island and $500/MWh in East of Central East. If there is a shortage of Ten-Minute Reserves in the New York Control Area and East of Central East but not Long Island, Ten-Minute Reserves will be priced at $450/MWh in the New York Control Area and $950/MWh in East of Central East (which includes Long Island). If there is a shortage of Ten-Minute Reserves in the New York Control Area and Long Island but not East of Central East, then Ten-Minute Reserves will be priced at $450/MWh in the New York Control Area (and New York City since it is nested in the New York Control Area) and $475/MWh in Long Island. Finally, if there is a shortage of Ten-Minute Reserves in the New York Control Area, East of Central East, and Long Island, then Ten-Minute Reserves will be priced at $450 in the New York Control Area, $950/MWh in New York City (East of Central East excluding Long Island) and $975/MWh in Long Island.

Table 6. NYISO Shortage Pricing ($/MWh)

Service	Shortfall	New York Control Area	East of Central East (New York City or Long Island)	Long Island only
Regulation	0 to 25	80	n/a	n/a
	> 25 to 80	180	n/a	n/a
	> 80	400	n/a	n/a
Thirty-Minute	0 to 200	50	25	25
	> 200 to 400	100	25	25
	> 400	200	25	25
Total Ten-Minute	> 0	450	500	25
Total Spinning	> 0	500	25	25

PJM's experience on September 10, 2013 provides an interesting example of the challenges of establishing prices that reflect shortage on a local rather than system-wide level.[32] On September 10, 2013, PJM was forced to involuntarily shed 16 MW during hours ending 16 and 17 in the ATSI transmission zone. During this event, the energy price for the ATSI zone during hour ending 17:00 through 20:00 was at or near its highest level ($1800/MWh) to reflect the fact that demand response resources were marginal (demand response offer cap was $1800/MWh) during those hours. While this is considered a shortage pricing event, the nature of the pricing is somewhat unique. The ATSI zone is not defined as a reserve zone for the purposes of identifying local reserve deficiencies. Thus, despite the fact that PJM shed load in the ATSI transmission zone, it did not set prices based on any reserve deficiency. Rather, prices were set because PJM invoked the ATSI Interface, a closed loop interface developed on July 17, 2013, to set energy prices any time emergency load management is issued in the ATSI zone.[33] This pricing technique appears to have resulted in prices that reflect the shortage event, but without accounting for reserve deficiencies on a local basis.

[32] *See* PJM, *Technical Analysis of Operational Events and Market Impacts During the September 2013 Heat Wave* at 24-30 (Dec. 23, 2013), *available at* http://www.pjm.com/~/media/documents/reports/20131223-technical-analysis-of-operational-events-and-market-impacts-during-the-september-2013-heat-wave.ashx (discussing the event); *id.* at 76 (explaining PJM's ATSI Zone Interface activation, a situation where emergency mandatory load management is issued in the ATSI transmission zone).

[33] *See* PJM, *ATSI Interface*, *available at* http://www.pjm.com/~/media/etools/oasis/system-information/atsi-interface-definition-update.ashx.

C. Operator Actions[34]

One of the most important differences between the RTOs and ISOs is what actually triggers shortage pricing. If an event is triggered too late, the market may be late to respond to the system's needs. Or, if operator actions taken to avoid a shortage[35] are not priced, prices may fail to appropriately signal tight market conditions. Every RTO and ISO has steps the system operator can and must take in order to avert a shortage.[36] However, if a goal of shortage pricing is to reflect in prices the cost of a shortage, it also may be important to price certain operator actions taken to avert a shortage.

The actions system operators take to avert a shortage, such as importing emergency energy or instituting a voltage drop, trigger shortage pricing in some RTOs and ISOs but not others. While NYISO and PJM invoke shortage pricing in response to certain operator actions, CAISO implements shortage pricing in a market run prior to an actual shortage occurring.[37] NYISO activates shortage pricing when Emergency Demand Response is dispatched. PJM considers a voltage drop to be an emergency action that triggers shortage pricing.[38] Different still, many of MISO's shortage events are triggered by ramping constraints that limit the system operator's ability to meet reserve requirements. That is, MISO has sufficient capacity to meet its reserve requirements, but has insufficient ramp capability to meet load and thus must dip into its reserve capacity to serve load. On the other hand, SPP specifically forbids ramping constraints from triggering shortage pricing, thus masking whether the RTO is short of operating reserves

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[34] Any discussion in this paper of issues related to demand response resources is intended only to reflect the manner by which these resources have participated in wholesale electricity markets in the past and is not a statement about how such resources may participate in the future.

[35] An operator emergency action, taken to avoid a shortage, could be in response to such things as actual load being higher than forecasted or the unexpected loss of a supply resource.

[36] For instance, if MISO anticipates a shortage, it can commit generation resources up to the emergency limits, commit emergency-only generation and demand response resources, curtail fixed demand bids and fixed export schedules. If these actions are not sufficient to relieve the shortage, MISO must then call an Emergency Energy Alert 1, or if needed Emergency Energy Alert 2. Declaring Emergency Energy Alert 2 then provides MISO with further steps it may take to mitigate any shortage, including directing LSEs to curtail Load Modifying Resources (a type of demand response resource), dispatching emergency demand response based on submitted offers, purchasing emergency energy, issuing a public appeal to reduce demand, and implementing a voltage reduction. *See* MISO, *Market Capacity Emergency Procedures RTO-EOP-002-r17* (effective June 1, 2014), *available at* https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=177019.

[37] For example, CAISO procures and prices operating reserves on a 15- minute basis in the Fifteen-Minute Market, a market run starts 37.5 minutes before the operating 15-minute interval (*e.g.*, 11:22 for Operating Reserves awarded from 12:00-12:15). If at 11:22, CAISO forecasts a shortage of operating reserves, it will implement shortage pricing in the Fifteen-Minute Market, 37.5 minutes before the actual shortage is predicted to occur.

[38] PJM, Manual 11 Energy and Ancillary Services Market Operations, at 33 *available at* http://www.pjm.com/~/media/documents/manuals/m11.ashx.

or short of ramping capability. These differences across RTOs and ISOs, combined with system and meteorological events, lead to different experiences with shortage events and shortage pricing in the RTOs and ISOs.[39]

Finally, the conditions that lead to shortage pricing may depend on other actions an RTO or ISO takes to prepare for tight system conditions. For instance, some RTOs and ISOs procure extra reserves to provide flexibility to respond to uncertain system conditions (e.g., under-forecast load, generation resource performance issues). In PJM, the day-ahead market procures a minimum of a certain percentage of the daily peak load in the form of Day-Ahead Scheduling Reserves. In 2013, the Day-Ahead Scheduling Reserves minimum was set at 6.91 percent. Day-Ahead Scheduling Reserves represented approximately 6800 MW of capacity and can respond in thirty minutes.[40] However, only the primary reserve requirement, the sum of the Ten-Minute Spinning Reserve requirement and the Ten-Minute Non-Synchronous Reserve requirement, is considered required reserves in PJM. This primary reserve represents about 2000 MWs. Therefore, shortage pricing in PJM only begins when approximately 70 percent of all the reserves in PJM are exhausted. The primary concern with procuring "extra" reserves is to ensure that doing so is reflected in the energy and ancillary services prices outside of shortage events.[41] Nevertheless, it is also important to appreciate how the decision to procure extra reserves impacts shortage pricing rules. To the extent extra reserves are procured out of a desire to avoid an involuntary load curtailment, one can question whether becoming deficient in such reserves should also trigger shortage pricing.

The following section explores some examples of how operator actions affect prices during tight system conditions.

In ISO-NE, operator actions related to the dispatch of demand response resources have resulted in instances of relatively low prices during tight system conditions. Under ISO-NE's currently-effective tariff, demand response is classified as a "non-dispatchable" resource and is therefore not eligible to set prices; rather, demand response resources are dispatched manually by the system operator during certain shortage or near-shortage events. However, the External Market Monitor notes that "[t]he activation of demand response in real-time can inefficiently depress real-time prices substantially below the marginal cost of the foregone consumption by the demand response resources,

[39] A more complete discussion of existing shortage pricing programs is included in the Appendices.

[40] Monitoring Analytics, *State of the Market for PJM*, at 316 (Mar. 13, 2013), *available at* http://www.monitoringanalytics.com/reports/pjm_state_of_the_market/2013/2013-som-pjm-volume1.pdf.

[41] A subsequent workshop will include discussion of this concern.

particularly during shortages or near-shortage conditions."[42] For example, on both July 22, 2011 and December 19, 2011, ISO-NE activated Real-Time Demand Response Resources to address operating reserve shortages and in both instances the Demand Response Resources were effectively on the margin during at least some of the shortage,[43] yet prices fell during these intervals – from over $450 in hour ending 16:00 on July 22, 2011 to just over $175 in hour ending 17:00; and from over $275 in hour ending 8:00 to $32 in hour ending 9:00 on December 19, 2011.[44]

Similarly, NYISO has experienced instances when operator actions and the dispatch of demand response resources have resulted in relatively low prices during tight system conditions. While demand response resources in NYISO have had a relatively small impact on annual average energy prices, they had a substantial affect in the hours when they were deployed and depressed real-time prices to levels well below their cost to the system – typically $500/MWh to curtail their load.[45] As detailed in Table 7 below, NYISO deployed demand response resources in 2012 on two occasions to meet system-wide needs, and on four occasions to meet needs in Southeastern New York. In NYISO, shortage pricing is only triggered when emergency demand response is dispatched and the quantity of demand response exceeds the capacity of other resources available but not committed to address the reserve deficiency. This only occurred once in 2012, on July 28.

Table 7 shows the events when the quantity of dispatched demand response was less than the quantity of other available capacity that was available but not committed to address the reserve deficiency. Prices during those (non-shortage pricing) events were below $130/MWh on all but two occasions. Of these two events, even for the higher-priced occasion when system needs exceeded the amount of demand response called, prices were at $409/MWh; this is below the typical cost ($500/MWh) of deploying demand response resources.[46] In response, NYISO's External Market Monitor recommended

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[42] Potomac Economics, *2012 Assessment of The ISO-New England Electricity Markets* at 79 (May 2013), *available at* http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2012_emm_rprt_final.pdf.

[43] That is, the MW amount of Demand Response Resources exceeded the MW shortage in Operating Reserves – with Demand Response, there was no shortage of Operating Reserves and without Demand Response there would have been a shortage.

[44] Potomac Economics, *2011 Assessment of The ISO-New England Electricity Markets* at 72-73 (June 2012), *available at* http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/emm_mrkt_rprt.pdf.

[45] Potomac Economics, *2012 State of the Market Report for the New York ISO Markets* at 68-71 (Apr. 2013), *available at* http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2012/NYISO2012StateofMarketReport.pdf.

[46] *Id.*

modifications of the market rules so demand response resources that have been deployed are eligible to set price in the real-time pricing methodology.[47]

Table 7. NYISO Real-time Prices and Available Capacity During Reliability Demand Response Deployments, 2012

	Reported DR (MW)	Available Capacity (MW)		Avg. LBMP ($/MWh)
		Average	Minimum	
New York Control Area Activation				
May 29	1081	1402	1214	$99
June 21	1877	3172	2635	$128
SE New York Activation				
June 20	669	2132	1974	$111
June 21	650	1979	1414	$235
June 22	677	3371	2055	$101
July 18	676	1307	172	$409

In summer 2013, NYISO implemented an Enhanced Scarcity Pricing Rule that was designed to ensure that real-time prices better reflect real-time shortages. NYISO deployed demand response on five days in 2013: July 15 through July 19. NYISO's External Market Monitor found the new shortage pricing rule was applied in the vast majority of intervals when demand response was actually needed (234 of 266 intervals),[48] although the External Market Monitor also noted that shortage pricing is only applied to internal locations, resulting in large differences between real-time prices at internal and external interfaces. The External Market Monitor noted that, when market participants expect a shortage event the next day, this can lead to incentives for participants to import day-ahead and buy back at non-shortage real-time prices.[49] This strategy, which can lead to additional export demand during likely shortage events, would not be profitable if shortage pricing were applied to external interface ties.

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[47] *Id.* at 85.

[48] Potomac Economics, *2013 State of the Market Report for the New York ISO Markets* at A-137 to A-140 (May 2014), *available at* http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2013/2013%20State%20of%20the%20Market%20Report.pdf.

[49] *Id.* at 67-68.

In sum, while it may be neither possible nor practical to price all operator actions in RTO and ISO markets, pricing some of the more common actions used to avert system shortages may in some instances result in more appropriate price formation during tight system conditions. Furthermore, the order of operator actions may also be important. For example, MISO's Independent Market Monitor recommended in its 2012 State of the Market report that MISO re-order its emergency procedures so that demand response resources are used more efficiently. Because demand response in MISO could only be called on after other, more costly, steps were taken to avoid a shortage, prices were not sending efficient signals.[50] As discussed above, operator actions can significantly impact price formation, and while such impacts may be of limited duration, these actions are often taken during tight conditions when appropriate price signals are paramount.

D. Schedule Coordination Across Seams

When one RTO or ISO declares a shortage or invokes shortage pricing, resources in neighboring RTOs and ISOs can see those price signals and respond. With the right timing of these events and the coordination of scheduling rules, imports from neighboring regions can help an RTO or ISO avoid a shortage and maintain reliability, while sending an efficient price signal to those resources that respond.

As discussed above, in summer 2013, NYISO implemented an Enhanced Scarcity Pricing Rule that was designed to ensure real-time prices better reflect real-time shortages. The NYISO External Market Monitor has noted that shortage pricing is only applied to internal locations, resulting in large differences between real-time prices at internal versus external interfaces leading to incentives for participants to import day-ahead and buy back at non-shortage real-time prices.[51]

The events of July 6, 2012 in MISO present a good example of where poor timing can lead to unintended consequences as importers attempt to react to high prices in a neighboring RTO or ISO. Prices were high on that date due to an operating reserve shortage caused by a combination of a 1.7 GW increase in load, the loss of a nearly-600 MW unit, and a 1.5 GW drop in imports from PJM. MISO's Independent Market Monitor identified the lack of coordinated interchange with PJM as the primary cause of a number of the high-price intervals.[52] In this case, net imports declined because prices

[50] Potomac Economics, *2012 State of the Market Report for the MISO Electricity Markets* at 9 (June 2013), *available at* https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=155430.

[51] Potomac Economics, *2013 State of the Market Report for the New York ISO Markets* at 67-68 (May 2014), *available at* http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2013/2013%20State%20of%20the%20Market%20Report.pdf.

[52] Potomac Economics, *2012 State of the Market Report for the MISO Electricity Markets* at ii (June 2013), *available at* https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=155430.

were approximately $100/MWh higher in PJM at the time. MISO remained in a shortage for another 30 minutes until imports from PJM responded to the new higher MISO interface price (at this point approximately 20 times higher than PJM). Because imports from PJM lagged the event by 30 minutes, the event was actually ending by the time the imports arrived, and the full effect of the imports was not felt until 2 pm, resulting in an overreaction to the shortage. By 2:10 pm interface prices shifted in response to overreaction, net imports had declined, and PJM prices were higher than in MISO while load was still increasing in MISO, leading to a second shortage.[53]

The effect of July 17, 2013, illustrated in Figure 1 below, provides a similar example. On this day MISO issued a Maximum Generation Emergency Alert from 14:00 to 19:00 due to higher than normal temperatures during the week of July 15th that led to higher load. MISO issued the Maximum Generation Alert because its projected peak-hour capacity surplus (the amount above the requirement) was expected to be less than 1 percent of its reserve requirements.[54] Prices rose sharply between 12:30 and 13:30 due to rapid load growth and a shift of approximately 600 MW in net-scheduled interchange towards PJM. As a result, MISO prices rose and net-scheduled interchange shifted toward MISO by roughly 1400 MW from 13:15 to 14:15 pm and net imports on other interfaces (i.e. with other systems) began to grow. Prices then moved and remained relatively low when load dropped after 13:30, wind output picked up, and MISO resource commitments increased. This is seen in Figure 1 by the sharp drop in prices after hour ending 14:00, when real-time LMP dropped from approximately $90 to near $50.[55]

[53] *Id.* at 7-8.

[54] David B. Patton, *Monthly Market Metrics Report July 2013* at 11 (Aug. 21, 2013), *available at* https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=157847.

[55] Todd Ramey, Vice President, System Operations & Market Services, MISO, *MISO Gas-Electric Coordination Update* at 4-6 (Oct. 17, 2013), *available at* http://www.ferc.gov/CalendarFiles/20131017102239-MISO-MEETING.pdf.

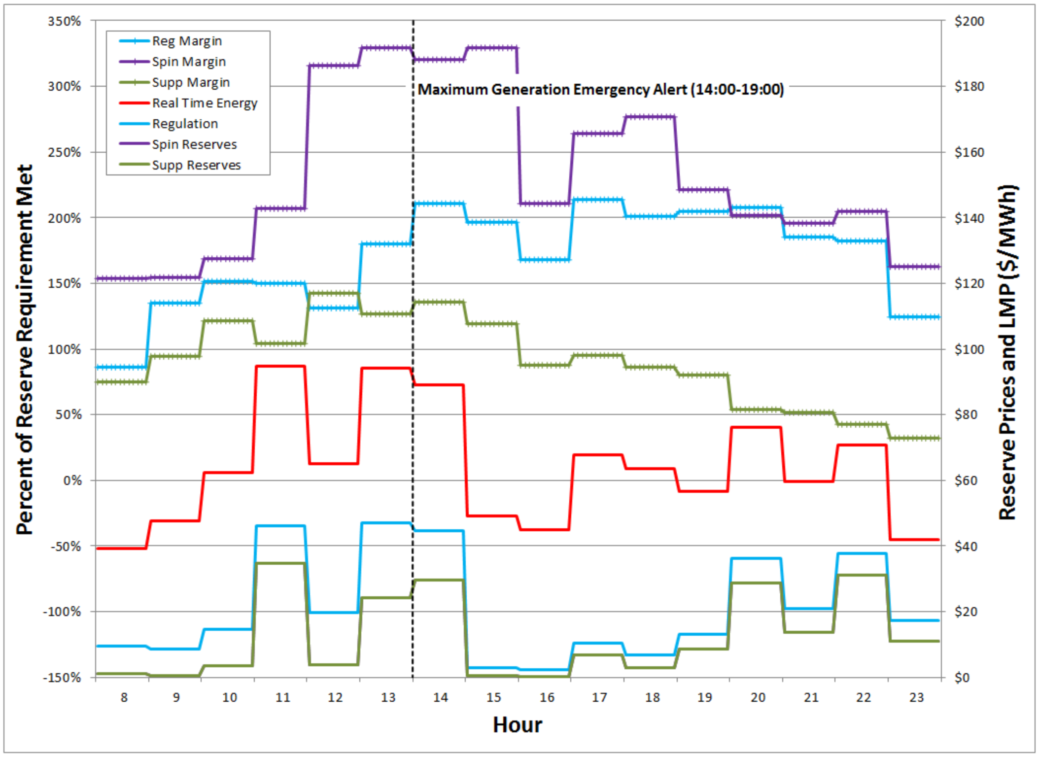

Figure 1. MISO Maximum Generation Emergency Alert, July 17, 2013.

While trade between RTOs and ISOs can lead to more efficient market outcomes, coordinating import/export transactions with emergency actions, such as those highlighted above, remains a challenge. The inability to coordinate can lead to inefficient flows between markets and can also lead to uplift payments, as resources committed to address a shortage event may be unneeded when higher than expected imports arrive from a neighboring region. This raises the question of whether any change to either shortage pricing rules or inter-ISO energy market coordination protocols could enhance the ability of neighboring regions to help alleviate shortage events.

V. Experience with Shortage Events

Discussed below are the RTOs' and ISOs' most recent experiences with shortages. Most RTOs and ISOs experience very few shortage events at all, and as a result, seldom see shortage pricing. When shortage pricing is invoked, oftentimes prices move as expected: prices increase when shortages occur, and decrease when the shortage ends. However, the duration of shortage pricing events appears to be very short. In addition, the effects of un-priced operator actions and inefficient imports leave open the question of whether the recent experiences with shortage pricing are achieving the goals discussed in Section III. That is, can infrequent, short duration shortage prices provide a signal for short-term performance and create incentives for efficient entry and exit?

A. CAISO

CAISO implemented shortage pricing on December 14, 2010 and since then has had only thirty-two 15-minute intervals of shortage pricing. As detailed in Table 8, twenty-eight of these intervals with ancillary service shortage pricing occurred in 2011, resulting in a direct cost of only $60,000.[56]

Table 8. CAISO 2011 Shortage Pricing Events

Month	Ancillary Service	Shortage Intervals	Average MW Shortfall	Ancillary Service Region
April	Spin	1	7.1	SP 26
May	Spin	3	11.5	SP 26/SP 26 Exp
June	Regulation-Up	8	19.9	SP 26 Exp
July	Regulation-Up	2	0.9	CAISO
July	Spin	2	13.8	CAISO
July	Non-Spin	9	112.7	CAISO
November	Spin	1	12.3	SP 26
November	Regulation-Up	2	10	SP 26

In 2012, there was only one 15-minute interval in which the ancillary service requirements were not met in either the hour-ahead or real-time markets. This was due to a 15 MW deficiency of Spinning Reserve and resulted in an incremental cost to the market of just $391.[57] In 2013, there were three 15-minute intervals in which the Regulation Down requirement could not be met in one reserve zone in either the hour-

[56] CAISO Department of Market Monitoring, *2011 Annual Report on Market Issues and Performance* (Apr. 2012), *available at* http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

[57] CAISO Department of Market Monitoring, 2*012 Annual Report on Market Issues and Performance* at 115 (Apr. 2013), *available at* http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

ahead or real-time markets. Because no incremental capacity was procured during these intervals, the incremental cost of this event to the market was $0.[58]

B. ISO-NE

Like CAISO, ISO-NE does not witness shortage events frequently. ISO-NE uses a protocol, Operating Procedure No. 4, which establishes criteria and guidelines for actions during existing or anticipated capacity deficiencies.[59] While there are ten numbered actions described in Operating Procedure No. 4 (detailed in the Appendix), ISO-NE does not have to follow a set order; it can take whatever actions it deems necessary for reliability. Operating Procedure No. 4 actions include: depleting Thirty-Minute Operating Reserve; dispatching real-time demand response resources; requesting voluntary load curtailment; purchasing emergency capacity and energy from neighboring balancing authorities; implementing a voltage reduction; and, appealing for voluntary load curtailment.[60] In addition, not every shortage is associated with the triggering of Operating Procedure No. 4. Thus, ISO-NE has the discretion to take actions under Operating Procedure No. 4 that may or may not trigger shortage pricing. Since June 1, 2012, ISO-NE implemented Operating Procedure No. 4 on three occasions: January 28, 2013; July 19, 2013; and December 14, 2013. In addition, ISO-NE had a shortage of Ten-Minute Operating Reserve on five occasions – the three Operating Procedure No. 4 events already mentioned, plus November 9, 2013 and January 28, 2014.

Since June 1, 2012, ISO-NE has experienced over 40 instances when system-wide Reserve Constraint Penalty Factors have been activated (where Reserve Constraint Penalty Factors were binding for Ten-Minute Operating Reserve and/or Total Operating Reserve) across 294 five-minute intervals, an average of 12.8 hours per year.[61] These are

[58] CAISO Department of Market Monitoring, *2013 Annual Report on Market Issues and Performance* (Apr. 2014), *available at* http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf. *See also* CAISO, *2013 Ancillary Service Scarcity Event Report* (Mar. 26, 2014) *available at* http://www.caiso.com/Documents/2013AncillaryServiceScarcityEventReport.pdf.

[59]ISO New England Inc., *Operating Procedure No. 4 – Action During a Capacity Deficiency* (effective Aug. 12, 2014), *available at* http://www.iso-ne.com/rules_proceds/operating/isone/op4/op4_rto_final.pdf (hereinafter, ISO-NE OP-4 Manual).

[60] *Id.* at 4-7.

[61] There are multiple instances where ISO-NE experienced shortages where periods of binding Reserve Constraint Penalty Factors were interrupted by a small number of intervals without binding Reserve Constraint Penalty Factors, which were counted as multiple instances of Reserve Constraint Penalty Factor activation, even though the events were clearly related. *See* ISO-NE, *Operating Reserve Deficiency Information – Historical Data – Updated*," (May 16, 2014), *available at* http://www.iso-ne.com/markets/othrmkts_data/fcm/doc/opr_reserve_deficiency_info_hist_data_updated_5_21_2014.zip. Therefore, simply looking at the number of instances of RCPF activation may be misleading, and it is more instructive to look at the number of intervals of Reserve Constraint Penalty Factor activation.

detailed in Table 9 below. The result in ISO-NE is that shortage pricing is only activated during a limited number of hours each year, and reserve prices are $0/MWh for all operating reserve products (excluding Regulation) in over 95 percent of hours.[62]

Table 9. ISO-NE Shortage Pricing Events, June 2012 – April 2014

Month	Total Number of Intervals	Average Total MW Shortfall	Ten-Minute Shortage	Operating Procedure No. 4 Events
Jul-2012	8	194	No	No
Oct-2012	2	9	No	No
Nov-2012	2	297	No	No
Jan-2013	14	139	Yes	Yes
Feb-2013	2	50	No	No
Mar-2013	4	109	No	No
Jun-2013	14	148	No	No
Jul-2013	80	564	Yes	Yes
Aug-2013	12	232	No	No
Sep-2013	26	87	No	No
Oct-2013	28	244	No	No
Nov-2013	20	354	Yes	No
Dec-2013	37	394	Yes	Yes
Jan-2014	15	360	Yes	No
Feb-2014	23	327	No	No
Mar-2014	6	367	No	No
Apr-2014	1	177	No	No

Figure 2 illustrates the events of January 28, 2013, when ISO-NE called an Operating Procedure No. 4 event. This day followed several severely cold days which culminated in tight capacity availability due to fuel limitations. The overnight dispatch of some gas-fired generating resources, called on to replace other fuel-limited resources, resulted in their operations being reduced due to their now-limited gas supplies. This made these

[62] Several recent Reserve Constraint Penalty Factor rule changes affect when shortage pricing will be invoked. For example, ISO-NE's External Market Monitor calculated that after ISO-NE raised the Reserve Constraint Penalty Factor for total Operating Reserves to $500/MWh on June 1, 2012, Thirty-Minute Reserve clearing prices exceeded $100 per MWh in 0.8 percent of the intervals during the rest of 2012, averaging roughly $174 per MWh in these intervals, rather than going short of Operating Reserves as ISO-NE would have done previously.

gas-fired generators unavailable for dispatch during the morning load ramp on January 28. Ten-Minute Operating Reserve and Regulation Reserve therefore could not be covered, leading to ISO-NE taking Operating Procedure No. 4 actions to help maintain operating reserves.[63] Shortly after 17:00 a generator tripped, causing ISO-NE to take Operating Procedure No. 4 Actions 1 and 2.[64] By 17:45 a generator had been dispatched to prevent any worsening of the shortage. [65] These actions resulted in Ten-Minute Spinning Reserve market-clearing price hitting a high of $526.84/MWh. In turn, LMP peaked at $780.89/MWh.[66]

This event illustrates how when the system operator is unable to meet one reserve requirement, here Thirty-Minute Operating Reserve, the price for that constraint increases and increases the prices for other products, Ten-Minute Spinning Reserve and energy in this example, as can be seen in Figure 2 below. In hour 17:00 when the system operator could no longer meet that requirement, the shadow price on that constraint jumped from $0 to near $300.[67]

[63] ISO-NE, *Winter Operations Summary: January – February 2013* at 9 (Feb. 27, 2013), *available at* http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

[64] ISO-NE informs all resources that a capacity shortage exists, begins to utilize Thirty-Minute Reserve, and implements a power caution for Operating Procedure No. 4 Action 1. ISO-NE dispatches real time demand resources in the amount and location required for Operating Procedure No. 4 Action 2.

[65] ISO-NE Internal Market Monitor, *2013 First Quarter Quarterly Market Report* at 14 (May 20, 2013), *available at* http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2013/qmrq1_2013.pdf.

[66] *Id.* at 13.

[67] ISO-NE was deficient of Regulating Reserves prior to being deficient of operating reserves. Though ISO-NE also has penalty factors for Regulating Reserve deficiencies, it is not apparent what price impact was seen in hours 17:00 and 18:00. Given that no Regulating Reserve deficiency was seen in hour 18:00, it is assumed that the increase in price that hour was unrelated.

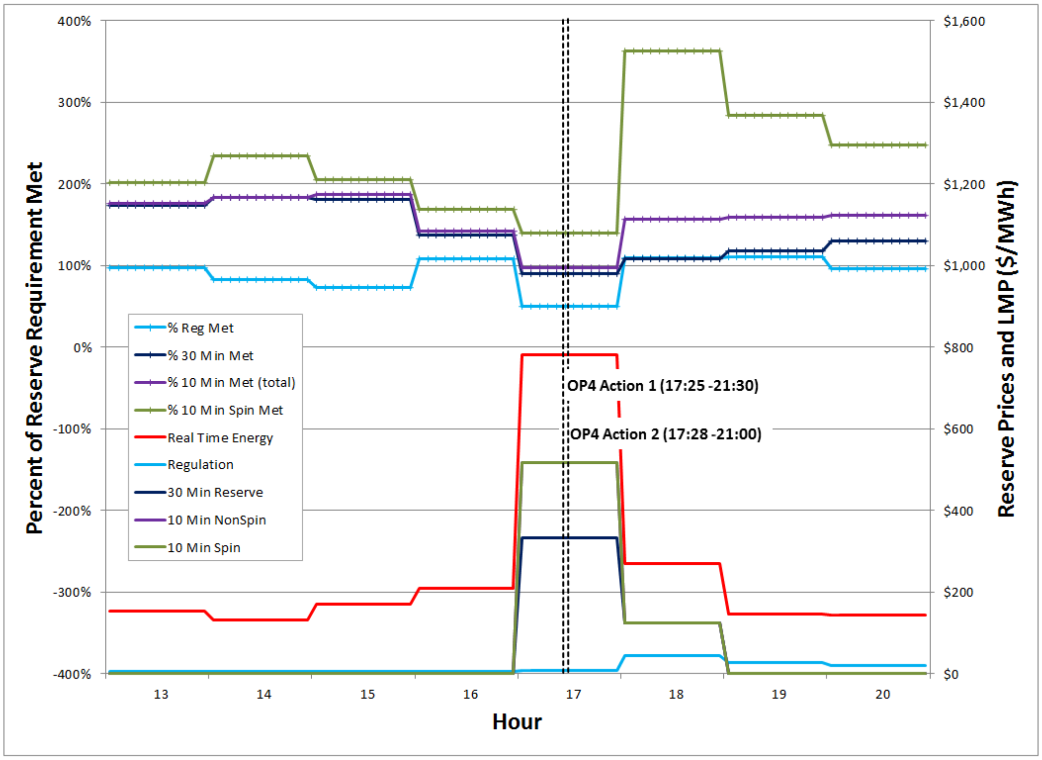

Figure 2. ISO-NE Operating Procedure No. 4 Event, January 28, 2013.

On July 19, 2013 the ISO-NE system was deficient in reserves over the peak hours and ISO-NE declared Operating Procedure No. 4. In addition to high electric load, there were 4,724 MW of generator outages and reductions over the peak hour of the day that contributed to the need to implement Operating Procedure No. 4.[68] High loads on July 19 coupled with generator unavailability resulted in tight capacity conditions. The system did not have sufficient reserves or capacity available to meet the reserve requirements by noon causing ISO-NE to declare Operating Procedure No. 4. Figure 3 below shows the times at which the various actions of Operating Procedure No. 4 were declared along with the actual operating reserves and reserve requirements throughout the Operating Procedure No. 4 event. Action 1 of Operating Procedure No. 4 was system wide, while actions 2, 3, and 5[69] excluded the Maine load zone due to transmission export

[68] As the summer seasonal claimed capability is normalized to 90 degrees F, some reductions are attributable to ambient air temperatures, since the temperature at the time of the peak on July 19 was 95 degrees F. Other outages and reductions are attributable to de-rated capacity due to mechanical failures.

[69] ISO-NE requests voluntary load curtailment of market participants' facilities in the New England New England Reliability Coordination Area/Balancing Area Authority for OP-4 Action 3. ISO-NE arranges to purchase available emergency capacity and energy, or energy only, (if capacity backing is not available) from market participants or neighboring New England Reliability Coordination Areas/Balancing Area Authorities for Operating Procedure No. 4 Action 5.

constraints.[70] Of particular interest here is that it appears that, even when certain reserve product requirements were not being met, prices, nonetheless, were flat or dropping. For instance, at 12:00 and 13:00 when the first two OP-4 actions were taken, procurement of Ten-Minute Non-Spinning Reserve and Thirty-Minute Operating Reserve were still deficient. While the price for Thirty-Minute Operating Reserve peaked at its limit of $500/MWh, the price of Ten-Minute Non-Spinning Reserve seems to have stayed flat, also at $500/MWh, rather than increase. Operating Procedure No. 4 actions were also taken at 14:20 and 15:00. At this point and lasting until after 18:00, the requirement for Thirty-Minute Operating Reserve was still not met, yet its price dropped. It is not clear why prices moved like this over the course of the day; but it does raise the question of what impact these Operating Procedure No. 4 actions have on market-clearing prices and whether out-of-market actions, in general, can have a price suppressing effect.

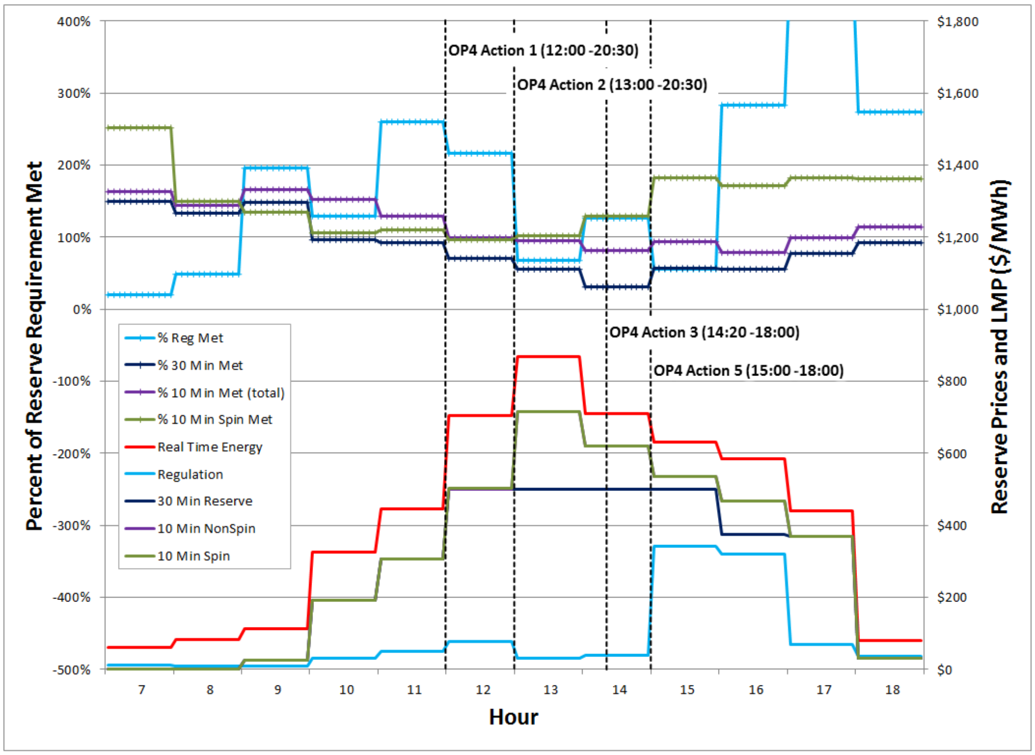

Figure 3. ISO-NE OP-4 Event, July 19, 2013.

[70] ISO-NE Internal Market Monitor, *2013 Third Quarter, Quarterly Markets Report* (Nov. 13, 2013), *available at* http://www.iso-ne.com/static-assets/documents/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2013/q3_2013_qmr_final.pdf.

December 14, 2013 appears to show a slightly different relationship between reserve deficiencies and prices. On this date, the actual load and the forecast load were very close, but during hour ending 17:00, the actual load started to diverge above the forecast value. At 17:00, significant imports into New England were curtailed, which, combined with the heavier than expected load, resulted in Operating Procedure No. 4 Action 1 being declared at 17:00, as shown in Figure 4. Prior to entering Operating Procedure No. 4, 21 MW in the Winter Demand Response Reliability Program were dispatched. At 17:07, ISO-NE declared Operating Procedure No. 4 Action 2 and dispatched 248 MW of Real-time Demand Response. ISO-NE declared Operating Procedure No. 4 Action 5 at 17:40 and scheduled 300 MW of Control Area to Control Area emergency capacity from 17:42 to 18:30. The preliminary integrated peak demand for hour-ending 18:00 on Saturday was 20,182 MW, 632 MW above the forecast 19,550 MW value.[71] In this instance, prices appear to move as one would expect, with increases in prices seemingly correlated to worsening deficiencies, and lessening deficiencies coupled with prices dropping. Taken with the events of July 19, 2013, it is unclear if one can draw definite conclusions regarding what effect out-of-market actions have on market-clearing prices.

[71] ISO-NE, Memorandum to NEPOOL Market Committee and NEPOOL Reliability Committee, *Implementation of ISO New England Operating Procedure #4 on Saturday, December 14, 2013* (Dec. 18, 2013), *available at* http://www.iso-ne.com/sys_ops/op4_action_archiv/2013/implementation_of_iso_new_england_operatiing_procedure_4_on_saturday_december_14_2013.pdf.

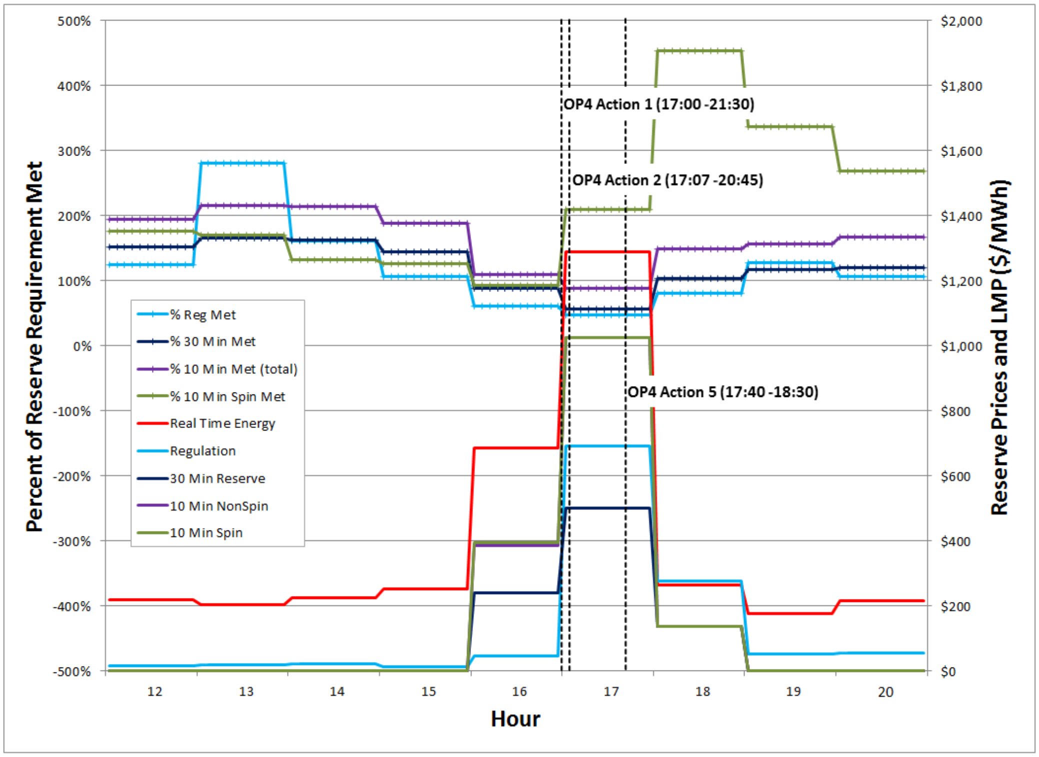

Figure 4. ISO-NE OP-4 Event, December 14, 2013

C. PJM

PJM invokes shortage pricing in two situations: when reserves fail to meet requirements, and when PJM institutes a voltage reduction. Like other RTOs and ISOs, shortage pricing is rare in PJM in part because PJM's use of Day Ahead Scheduling Reserves, as discussed earlier, means that PJM only uses shortage pricing when it has exhausted approximately 70 percent of all reserves. In fact, PJM did not have any reserve shortage events or shortage pricing during 2010, 2011, or 2012.

The shortage events PJM experienced in 2013 illustrate some of the complexities associated both with incorporating the use of demand response into prices and in defining local reserve zones. In 2013, PJM did not have any reserve shortage events, though shortage pricing was in effect in certain zones on three different days due to emergency operations. First, PJM experienced a shortage of Non-Synchronous Reserve in the ATSI region that led to LMP in excess of $1000/MWh and shortage pricing for several hours on July 18. As discussed in more detail above, this occurred again on September 10 and also led to load shedding in the AEP zone. Finally, on September 11, 2013, PJM experienced a shortage of Non-Synchronous Reserve and took several actions to ensure reliability. PJM deployed long-lead-time demand response in the AEP and ATSI and other zones, and issued a voltage reduction warning in the AEP and ATSI zones. As on September 10, demand response set the market-clearing LMP at its limit of $1800/MWh in the ATSI zone.[72] The impacts of these events on pricing in PJM are shown in the figures that follow.

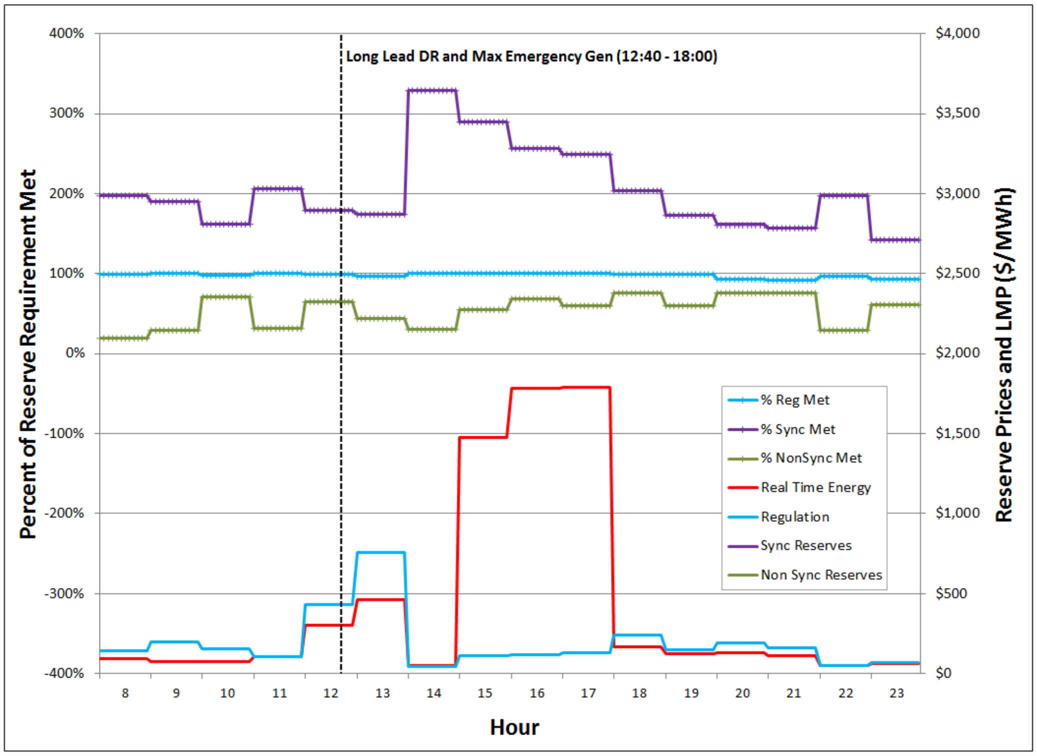

Figure 5. PJM ATSI Zone Shortage, July 18, 2013.

[72] *See* PJM Interconnection, *Technical Analysis of Operational Events and Market Impacts During the September 2013 Heat Wave* at 76 (Dec. 23, 2013), *available at* http://www.pjm.com/~/media/documents/reports/20131223-technical-analysis-of-operational-events-and-market-impacts-during-the-september-2013-heat-wave.ashx. *See also* Monitoring Analytics, LLC, *State of the Market for PJM* at 117 (Mar. 13, 2013), *available at* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013-som-pjm-volume1.pdf. LMPs in PJM in excess of $1000 per MWh reflect shortage pricing because bids in PJM cannot exceed $1000 per MWh.

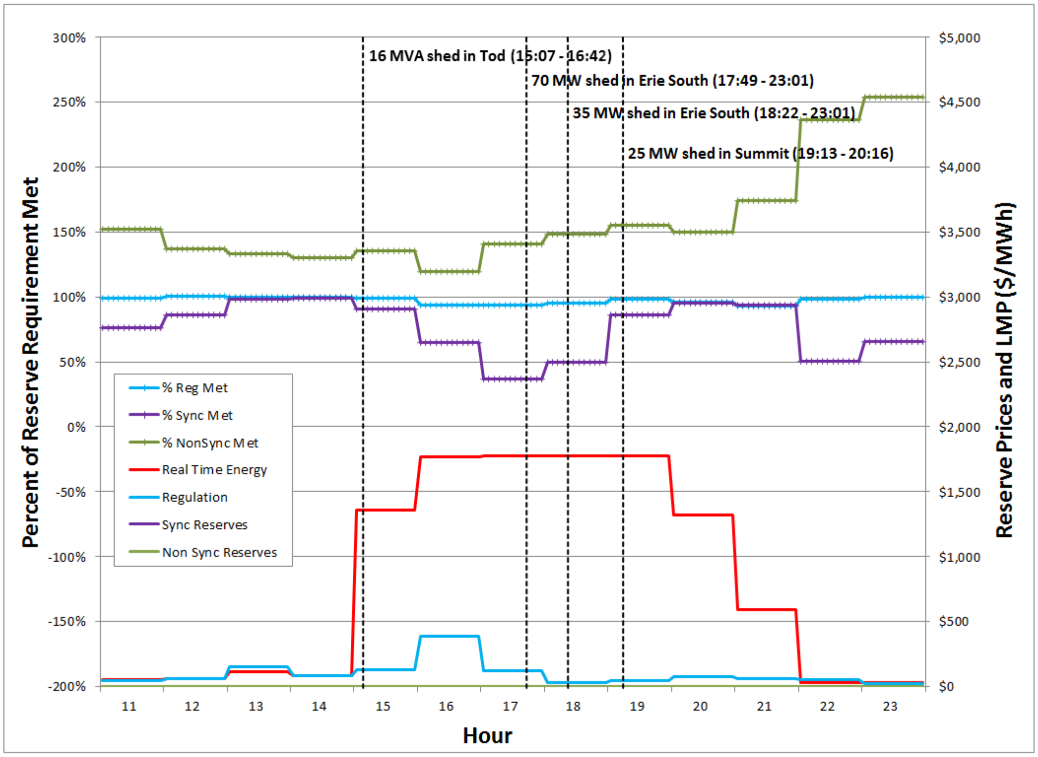

Figure 6. PJM ATSI Zone Load Shed, September 10, 2013.

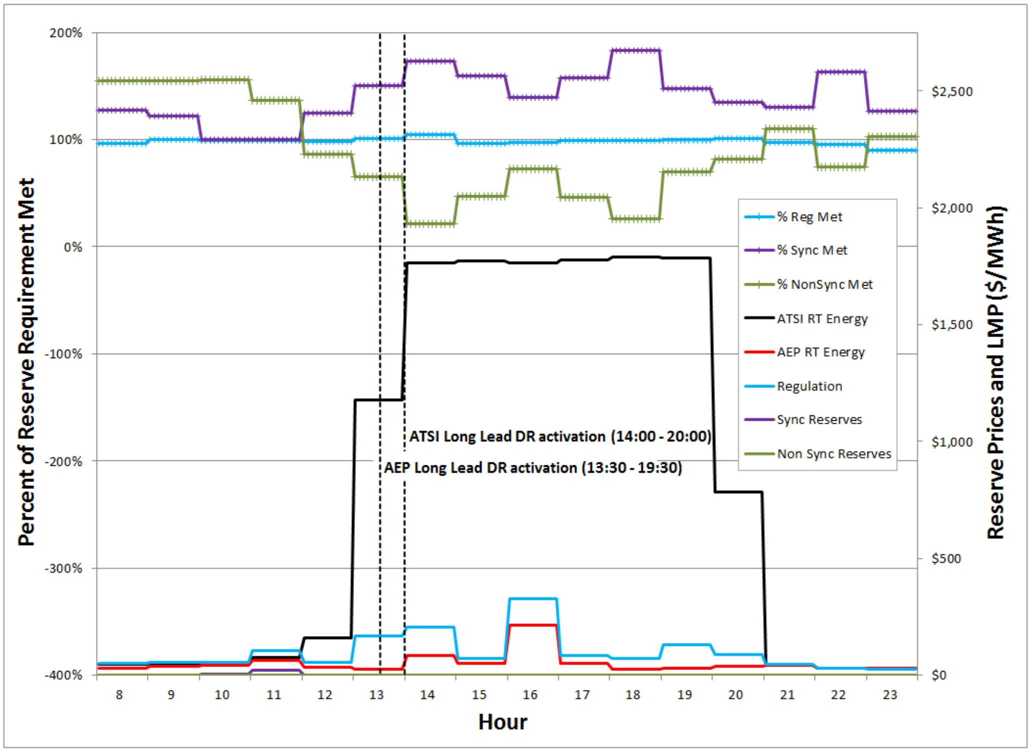

Figure 7. PJM ATSI and AEP Zones Load Shed, September 11, 2013.

D. NYISO

NYISO presents yet a slightly different example. Like PJM, it invokes shortage pricing when it is unable to meet its reserve requirements or when a specific operator action is taken: dispatch of Emergency Demand Response. However, while there were not a significant number of intervals[73] with shortage events in 2013, these events had a substantial impact on NYISO's energy prices, accounting for 7 to 8 percent of average Locational Based Marginal Price in 2013. Table 10 below, taken from NYISO's 2013 State of the Market report, shows the number of shortage events and how they affected annual average energy prices in NYISO.[74] Transmission shortage constraints are included in the table because they are addressed, priced, and affect the system in a way

[73] There are more than 105,000 5-minute dispatch intervals in a year (8760 hours multiplied by 12 5-minute intervals per hour).

[74] Potomac Economics, *2013 State of the Market Report for the New York ISO Markets* at 66 (May 2014), *available at* http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2013/2013%20State%20of%20the%20Market%20Report.pdf.

that is quite similar to shortages of energy or operating reserves.[75] Transmission constraints are priced based on redispatch costs, subject to an administrative price cap.

Table 10. NYISO Real-time Shortages and Price Impacts, 2013

	Shortage Frequency (# of Intervals)	Avg Shortage Price ($/MWh)	Impact on Zone Prices ($/MWh)				
			West	Capital	Hudson	NYC	LI
Operating Reserve Shortages							
Ten-Minute East	246	$445		$1.04	$1.04	$1.04	$1.04
Regulation	1349	$165	$1.46	$1.46	$1.46	$1.46	$1.46
Other New York Control Area Requirements	87	$306	$0.25	$0.25	$0.25	$0.25	$0.25
Transmission Shortages							
Dunwoodie - Shore Road	110	$974					$1.02
E. Garden City - Valley Stream	297	$3,310					$0.54
Leeds-Pleasant Valley	53	$2,664		$0.03	$0.41	$0.49	$0.49
Other Facilities	363	$2,721	$1.01	$0.33	$0.29	$0.58	$0.57
Scarcity Pricing During DR Activation							
New York Control Area	124		$0.39	$0.33	$0.27	$0.23	$0.24
Southeast New York	148				$0.47	$0.43	$0.44
Total			$3.12	$3.44	$4.20	$4.49	$6.05
Potential Net Revenue ($/kW-year):			$27	$30	$37	$39	$53

E. MISO

Though MISO only invokes shortage pricing when it is unable to meet its reserve requirements, it represents the relative opposite case in terms of the frequency of shortage pricing events. MISO experiences shortages relatively more times per year than the other RTOs and ISOs; however, there are still nominally few events and the events are short-lived and appear to have little effect on settlement prices. Table 11[76] below shows the percentage of intervals during which MISO experienced a shortage of any kind from

[75] NYISO's external market monitor found many intervals when gas turbines were not dispatched to relieve a constraint even though their marginal cost was lower than the Transmission Shortage Cost of $4,000 per MWh and therefore supports the implementation of a graduated transmission demand curve that would better reflect the severity and value of transmission shortages. *Id.* at 66-67.

[76] Data for Table 11 was compiled from 2009-2012 Independent Market Monitor's State of the Market reports and Quarterly Reports for 2013. *See, e.g.*, Potomac Economics, *2009 State of the Market Report for the Midwest ISO* at 52, Figure 30, 54, *available at* https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=17882.

2009 through summer 2013.[77] As can be seen in the table, MISO saw few actual instances of shortages in absolute terms even though shortages were more frequent than in the other RTOs and ISOs.

MISO's Independent Market Monitor attributed the experience of 2009 to a combination of mild weather and a sizable capacity surplus.[78] In addition, MISO reduced its Regulating Reserve minimum requirement in mid-2009. In 2010, MISO also saw infrequent shortages, again explained by the relative surplus of available capacity on the system, according to MISO's Independent Market Monitor. However, MISO's experiences in 2010 illustrate a common occurrence. There were 449 5-minute intervals[79] where the system marginal price exceeded $175/MWh. On average these price spikes lasted only 1.6 intervals, or 9 minutes. The longest lasted eight intervals, or 40 minutes.

[77] Data for MISO begins in January 2009 when its separate balancing areas were consolidated into one and MISO commenced its ancillary services market. Data for 2013 and 2014 are not yet available.

[78] Potomac Economics, *2009 State of the Market Report for the Midwest ISO* at 9, *available at* https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=17882.

[79] Because the State of the Market reports do not provide more detailed data, it is impossible to determine if these shortage events occurred consecutively or independently. For instance, if some of the 778 5-minute intervals in 2009 during which there was a Regulation shortage occurred consecutively (e.g., twelve in a row over the course of a settlement hour), it would have a larger impact on prices than if a shortage occurs during only one 5-minute interval of a settlement period. *See id.* at Figure 30. This figure shows both market clearing prices and percentage of intervals with shortages.

Table 11. MISO Percent of 5-Minute Intervals With Shortage Prices[a]

Year	Regulation	Spinning Res.	Non-Spin Res.
2009	< 1%	1.4%	> 0.0%
2010	< 0.2%	1.1%	> 0.0%
2011	< 0.5%	< 1.1%[b]	> 0.0%
2012	< 0.5%	< 1%	< 0.5%
2013[c]	< 0.2%	< 1.6%	> 0.0%

Notes:
a. The exact percentage of intervals with shortage pricing is not always reported. However, rough approximations can be made based on published tables and graphs.
b. The specific percentage of Spinning Reserve shortage intervals for 2011 was not reported by the Independent Market Monitor. However, it was reported to be lower than the rate in 2010.
c. January through August 2013 only.

In 2011, MISO saw much the same shortage activity as in 2010, with most shortages due to system ramping demand.[80] High priced events (system marginal price greater than $175/MWh) lasted, on average, only 1.8 intervals.[81] In 2012, MISO experienced unusually warm weather, leading to more expensive periods of shortages during the summer. This included all-time peaks in July and shortage prices for operating reserves between $1000/MWh and $2400/MWh. As can be seen in Table 11, the percentage of 5-minute intervals with shortage pricing did not change; however, the actual prices reflected in market clearing prices did increase significantly. Finally, through August 2013, MISO saw fewer shortages than 2012, attributable to lower load, according to the Independent Market Monitor, with these shortages resulting in smaller increases in the market clearing prices for Regulation, Spinning, and Supplemental Reserves. For instance, shortages of Regulation dropped from 55 in the summer of 2012, to only 37 in the summer of 2013. As a result, these shortages added only $0.52 to the price of Regulation in 2013, while they added $2.75 in the previous summer.[82]

Figure 8 below shows the events of April 1, 2013. On this day, MISO experienced an operating reserve shortage starting at interval 19:30 and lasting through interval 19:55 (i.e., hour ending 20:00 in Figure 8). Because of this shortage, the marginal energy component of LMP rose to $936, the market-wide Regulation market clearing price was $850, market-wide Spinning Reserve market clearing price was $783, and the market-wide Supplemental Reserve market clearing price was $720. The operating reserve

[80] Potomac Economics, *2011 State of the Market Report for the MISO Electricity Markets* at A-52 (June 2012), *available at* https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=132800.

[81] *Id.* A-45.

[82] Potomac Economics, *IMM Quarterly Report: Summer 2013 June-August* at 7-8 (Sept. 2013), *available at* https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=160510.

deficiency worsened over the course of the hour, with the system operator eventually clearing less than 70 percent of the operating reserve requirement. Therefore, at 19:55 all LMPs and market clearing prices were increased by approximately $450. Even though this shortage occurred over only six intervals, it impacted the entire hour's settlement values.[83] The shortage event ended after the 19:55 interval and LMPs and market-clearing prices dropped immediately after, as seen in Figure 8.

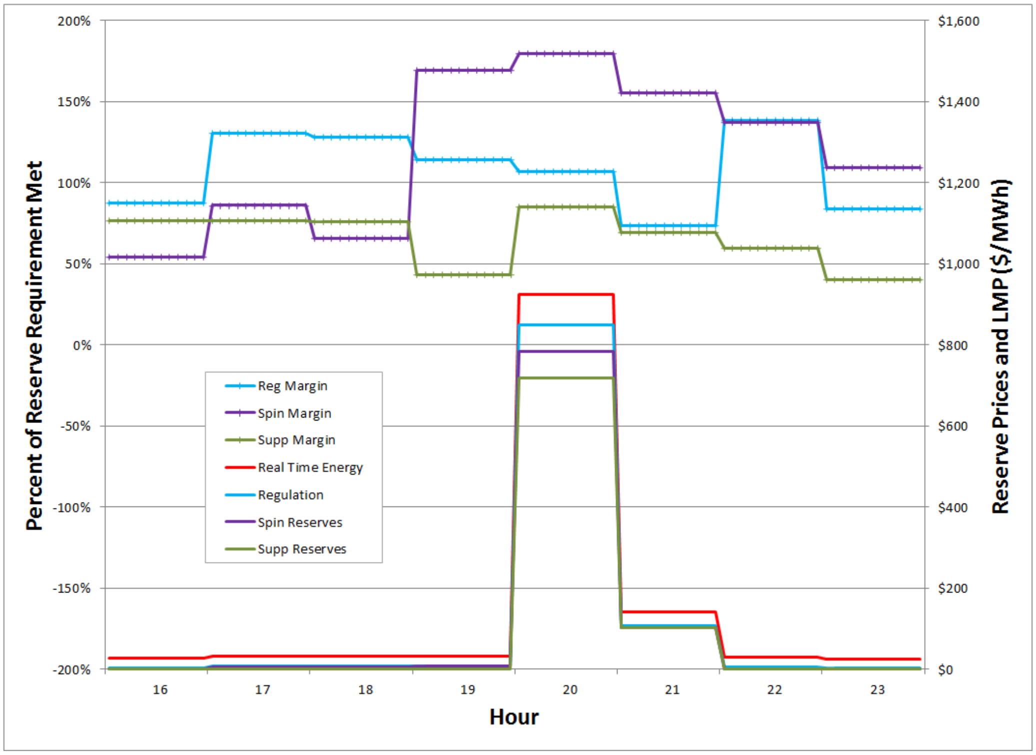

Figure 8. MISO Operating Reserve Shortage Event, April 1, 2013.

VI. Concluding Remarks

Based on a review of the existing RTO and ISO shortage pricing rules and the impacts that actual shortage events have had over the last several years, Commission staff observe that, while RTOs and ISOs all tend to define a shortage in the same way, the shortage pricing triggers differ across markets as do the energy and ancillary service prices that

[83] MISO's Operating Reserve requirements can change from hour-to-hour and were unavailable to staff at the time of writing. Thus it is not possible to determine directly from Figure 8 which Operating Reserve product(s) was deficient.

result from shortage events. Further, shortage pricing may only be reflected in the actual dispatch interval in which it occurs. For instance, if a shortage occurs only over the course of one or two 5-minute dispatch intervals, only the hourly price for those intervals will reflect the shortage event. To the extent settlements are based on hourly rather than 5-minute or 15-minute prices, this may mute the intended price signal. In addition, shortage events are rare in most RTOs and ISOs, sometimes not occurring at all over the course of a year. Given this, it is an open question whether there is a need to reduce the settlement interval to enhance the price signal associated with shortage pricing.

Some operator actions taken to avert a shortage are not reflected in market-clearing prices. In some RTOs and ISOs, for example, calling emergency demand response occurs only when prices hit a certain level, yet that strike price is not reflected in LMP in any way. In others, those actions do trigger shortage pricing. This raises the question of whether operator actions taken to avoid a shortage can or should be reflected in energy and ancillary services prices.

Not all RTOs and ISOs invoke shortage pricing at the same time. Some RTOs and ISOs invoke shortage pricing prior to an actual shortage event while others only invoke shortage pricing when an actual shortage occurs. Is it economically efficient (either in the short-run or long-run) to invoke shortage pricing prior to an actual reserve deficiency?

Because of the lag between price signals and import and export scheduling, it is difficult for market participants to efficiently schedule exports and imports to respond to shortage conditions, sometimes leading to inefficient behavior. Can either shortage pricing rules or inter-ISO energy market coordination protocols be modified to enhance the ability of neighboring regions to help alleviate shortage events?

Appendix 1 California Independent System Operator Corporation (CAISO)

Shortage Definition

CAISO declares a shortage when supply is insufficient to meet any of the minimum procurement requirements for energy and Regulation-Up, Spinning Reserve, Non-Spinning Reserve or Regulation-Down.[84] Though CAISO must meet the minimum requirements established by the Western Electricity Coordinating Council,[85] it bases its shortage-trigger on its own criteria. CAISO-declared emergencies specifically related to deficiencies in Regulation Reserve or operating reserves depend on the severity of the deficiency, as described in Table 12 below.

Through the market co-optimization process, CAISO utilizes available resources to provide energy and operating reserves in the most efficient manner to clear the energy market, manage congestion, and procure required operating reserves. In so doing, CAISO honors submitted self-scheduled energy unless it is unable to satisfy 100 percent of the operating reserve requirements. In such cases, CAISO curtails all or a portion of a submitted self-schedule of energy to allow ancillary service-certified resources to be used to meet the operating reserve requirements.[86]

Shortage Pricing

When CAISO determines that there is or will be an operating reserve deficiency, the shortage pricing mechanism will be triggered and the market clearing prices for operating reserves will be set by the appropriate value in CAISO's Scarcity Demand Curves, detailed in Table 12 below.[87] At the same time, energy prices may also rise due to the impact of shortage pricing, or may be unaffected by the rise in ancillary service prices, depending on the ability of the marginal unit to provide energy only or energy and operating reserves. If, during an operating reserve deficiency, the CAISO dispatches a generator which can provide either energy or operating reserve, to provide one additional MW of energy, the price of energy will include the opportunity cost of this unit not being

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[84] CAISO, Tariff, § 27.1.2.3.

[85] The Western Electricity Coordinating Council requires a balancing area authority to maintain contingency reserves equal to the greater of (i) the loss of the single greatest contingency or (ii) the sum of three percent of hourly integrated load (generation minus station service minus net actual interchange) plus three percent of hourly integrated generation (generation minus station power service). *See Regional Reliability Standard BAL-002-WECC-2 – Contingency Reserve*, 145 FERC ¶ 61,141 (2013).

[86] CAISO, Tariff, §§ 40.6.1 and 40.6.2

[87] CAISO, Tariff, §27.1.2.3. CAISO is required to review the performance of the Scarcity Reserve Demand Curves every three years and assess whether changes are necessary. This can be done more frequently if CAISO determines more frequent reviews are appropriate. CAISO, Tariff, §27.1.2.

available to provide operating reserves, a more valuable product.[88] On the other hand, if the capacity used to provide the incremental energy could not have been used to fulfill an operating reserve requirement, the price of energy will not be directly affected by shortage pricing.[89] The energy and operating reserve co-optimization models will determine the energy LMP and operating reserve market-clearing prices simultaneously.

Table 12. CAISO Shortage Pricing

Reserve Product	Reserve Product
Regulation-Up	$200
Spinning Reserve	$100
Non-Spinning Reserve	
Shortage > 210 MW	$700
210 MW > Shortage > 70 MW	$600
70 MW > Shortage	$500
Maximum Upward Sum	$1000 ($200+$100+$700)
Regulation-Down	
Shortage > 84 MW	$700
84 MW> Shortage > 32 MW	$600
32 MW > Shortage	$500

Non-Spinning Reserve requirement cannot be met, Spinning and Regulating Reserve requirements can be met

If CAISO is short of Non-Spinning Reserve, the Non-Spinning Reserve market-clearing price will depend on the severity of the shortage. As shown in the table above, if there is a shortage less than 70 MW, then the Non-Spinning market-clearing price is set at $500. A shortage of between 70 MW and 210 MW would result in a shadow price of $600. And a shortage of greater than 210 MW would result in a shadow price of $700. The market-clearing prices for Spinning Reserve and Regulation-Up will be calculated as normal, accounting for the opportunity cost now associated with Non-Spinning Reserve. If the CAISO dispatches a generator in order to provide one additional MW of energy during shortage conditions, the price of Energy will include the opportunity cost (i.e. the

[88] Locational marginal prices are designed to keep the resource indifferent between providing energy and ancillary services. In the case where the resource is capable of providing both energy and operating reserves, energy prices reflect the opportunity cost of not providing operating reserves.

[89] It is possible that capacity used to provide energy could not have been used to provide operating reserves due to ramp rate requirements. In CAISO, for example, a generator receiving an award for Spinning Reserves must be able to ramp to its awarded quantity in 10 minutes.

$500, $600, or $700 shadow price) of the unit if it is capable of but prevented from providing Non-Spinning Reserve.

Spinning Reserve requirement cannot be met; Non-Spinning and Regulating Reserve requirements can be met

In this case, the shadow price associated with Spinning Reserve, as indicated by the table above, is $100. The market-clearing price for Regulation-Up would be established as normal, but would reflect the opportunity cost of $100 for not providing Spinning Reserve. The market-clearing price for Non-Spinning Reserve is set as normal with no shortage pricing impact.[90] If CAISO dispatches a generator in order to provide one additional MW of energy during shortage conditions, the price of energy will include the opportunity cost (*i.e.*, the $100 shadow price) of the unit if it is capable of but prevented from providing Regulation-Up.[91]

Regulation-Up Reserve requirement cannot be met; Non-Spinning and Spinning Reserve requirements can be met

Again, as indicated in the table above, the shadow price associated with Regulation-Up would be $200 when the operator is unable to meet the Regulation-Up minimum requirement. Market-clearing prices for Spinning Reserve and Non-Spinning Reserve would be unaffected. If the CAISO dispatches a generator in order to provide one additional MW of energy during shortage conditions, the price of energy will include the opportunity cost (*i.e.*, the $200 shadow price) of the unit if it is capable of but prevented from providing Regulation-Up.

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[90] In a scenario where a more valuable reserve product is short but a less valuable one is not, the MCP of the less valuable product never reflects shortage conditions both because that product is not short and also because there is no opportunity cost to a resource providing that product, unlike if the resource were providing a more valuable product and there is a shortage of a less valuable product.

[91] There are other combinations of shortages that are not described here. In these cases MCPs are additive. In the event that there is also a shortage of Non-Spinning Reserve greater 70 MW, between 70 MW and 210 MW, or greater than 210 MW, then a shadow price of $500, $600, or $700, respectively, would be added to the MCPs of Regulation-Up and Spinning Reserves.

For example, if there is both a shortage of 60 MW of Non-Spinning Reserve to a shortage of Spinning Reserve and Regulation-Up reserve, the shadow price of Non-Spinning Reserve would be $500, and this would then be added to the shadow prices of Regulation-Up and Spinning Reserves. Therefore, the Regulation-Up MCP would be $800 ($300 + $500) and the Spinning Reserve MCP would be $600 ($100 + $500). A Shadow Price of $1000 for Regulation-Up is possible when there is a shortage of Regulation-Up and Spinning Reserve, as well as a Non-Spinning Reserve shortage greater than 210 MW. When this occurs the shadow price associated with the shortage of each product is summed ($200+$100+$700) to determine the total Shadow Price. For example, the highest shadow price associated with Spinning Reserve is $800 ($100+$700).

Regulation-Up Reserve and Spinning Reserve requirements cannot be met; Non-Spinning Reserve requirement can be met

In this scenario, because Regulation-Up is a more valuable product than Spinning Reserve and both are short, the market-clearing price associated with Regulation-up is equal to the sum of the $100 shadow price for Spinning Reserve and the $200 shadow price for Regulation-Up Reserve, or $300. The market-clearing price for Spinning Reserve is equal to $100. If the CAISO dispatches a generator in order to provide one additional MW of energy during shortage conditions, the price of Energy will include the opportunity cost (*i.e.*, the $300 shadow price) of the unit if it is capable of but prevented from providing both Regulation-Up and Spinning Reserve. If the unit is only capable of providing Spinning Reserve, only the $100 shadow price will be added to the price on Energy.

Regulation-Down Reserve requirement cannot be met; all other reserve requirements can be met.

The shadow price associated with Regulation-Down depends on the severity of the shortage, as indicated by the table above. There will be no impact on the shadow price of energy because, in this case, the system operator needs downward ramping capability (*i.e.*, for resources to provide less energy to the system) and therefore there is no opportunity cost to the resource for providing one additional unit of energy.

Appendix 2 ISO New England Inc. (ISO-NE)

Shortage Definition

ISO-NE defines an operating reserve shortage as a situation in which there is insufficient operating reserve available to meet the operating reserve requirements for the system or any Reserve Zone at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors.[92] An operating reserve shortage is the trigger for a shortage event, which is defined as "any period of thirty or more contiguous minutes of system-wide Reserve Constraint Penalty Factor activation, defined as being short of Operating Reserves."[93] While the Reserve Constraint Penalty Factor -based administrative shortage pricing only applies to real-time prices and operations, ISO-NE has several other tools at its disposal to address actual or anticipated operating reserve shortages.

After ISO-NE has run its Day-Ahead market, which clears resources against as-bid load and reserve requirements, ISO-NE runs a Reserve Adequacy Analysis which attempts to ensure enough resources have been committed during every hour to meet its forecasted load plus forecasted reserve requirements for the remaining hours of the current day and the next day. If needed, ISO-NE will commit additional resources in the Reserve Adequacy Analysis over and above what cleared in the day-ahead market to meet its forecasted real-time energy and operating reserve requirements. However, sufficient resources may not always be available in the Reserve Adequacy Analysis to meet the day-ahead forecasted needs. If the sum of day-ahead fixed demand bids and fixed external transaction sales cannot be satisfied with the sum of all scheduled external transaction purchases, cleared increment offers, and available generation at its economic maximum limit, ISO-NE's software will issue an Emergency Condition warning message due to a shortage of economic supply in the day-ahead energy market. In order to achieve power balance in that situation, all fixed external transaction sales are considered to be dispatchable at $1,000/MWh and ISO-NE will reduce or eliminate scheduled energy deliveries associated with any remaining price-sensitive demand bids (including external transaction sales) and decrement (virtual) bids, from lowest price to highest until power balance is achieved.[94]

Third, ISO-NE has a set of operating procedures to deal with capacity deficiencies and other abnormal system conditions. ISO-NE's primary operating procedure for addressing

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[92] ISO-NE, Tariff, § III.2.7A.

[93] ISO-NE, Tariff, § III.13.7.1.1.1.

[94] ISO-NE, Tariff, § III.2.6(b). If those steps are insufficient, ISO-NE will reduce all remaining fixed demand bids proportionately (by ratio of load MW) until balance is achieved and will set LMP values equal to the highest offer price of all on-line generation, increment offers or external transaction purchases, or the price from the previous step, whichever is higher.

capacity deficiencies is Operating Procedure No. 4 which establishes criteria and guides for actions during existing or anticipated capacity deficiencies. While there are 10 numbered actions described in Operating Procedure No. 4, ISO-NE does not have to follow a set order; it can take whatever actions it feels will best aid reliability. Operating Procedure No. 4actions include the following groups of actions: 1) inform all resources with a capacity supply obligation to prepare to provide all associated capability and begin to allow depletion of Thirty-Minute Operating Reserve; 2) dispatch real-time demand response resources; 3) request voluntary load curtailment of market participants' facilities in the New England Reliability Coordination Area/Balancing Area Authority; 4) implement a power watch ; 5) arrange to purchase available emergency capacity and energy, or energy only, from market participants or neighboring Reliability Coordination Areas/Balancing Area Authorities; 6) implement a 10-minute lead time voltage reduction of 5 percent of normal operating voltage, dispatch Real-Time Emergency Generation Resources in the amount and location required, and alert NYISO that sharing of reserves within the Northeast Power Coordinating Council may be required; 7) request that generation without a Capacity Supply Obligation voluntarily provide energy for reliability purposes; 8) implement a short lead-time (less than 10 minutes) voltage reduction of 5 percent of normal operating voltage; 9) request all of the customer generation not contractually available to market participants and request voluntary load curtailment by large industrial and commercial customers; 10) initiate radio and television appeals for voluntary load curtailment; and 11) request that each New England state governor reinforce power warning appeals. When the system conditions have improved sufficiently, ISO-NE will cancel these actions, though the order of cancellation may be different from the order of initiation.[95]

Shortage Pricing

ISO-NE's administrative shortage pricing mechanism is triggered whenever there is insufficient operating reserve available to meet the operating reserve requirements for the system or any reserve zone, or sufficient operating reserve is not available at a redispatch cost equal to or less than that specified by the reserve constraint penalty factors. The reserve constraint penalty factors thus serve a dual purpose – they allow ISO-NE's software to achieve a feasible solution when there are insufficient reserves from actual resources[96] and they set a price ceiling limiting the maximum cost incurred to redispatch resources to provide reserves.[97] Reserve constraint penalty factors may be reflected in

[95] ISO-NE OP-4 Manual at 4-7.

[96] In this case, reserve constraint penalty factors are effectively a "virtual" supply resource supplying reserves at the reserve constraint penalty factor price level.

[97] In this instance, the "shortage" will be economic, not physical, since additional reserves could have been created at a price higher than the reserve constraint penalty factor. This additional redispatch, however, would be costly both in dollars and in the amount of time it would take ISO-NE's software to find a feasible solution to its dispatch problem.

energy prices. ISO-NE is unusual among the RTOs, as it invokes emergency procedures (Operating Procedure No. 4) after it has invoked shortage pricing.

ISO-NE procures several categories of operating reserves to allow it to meet North American Electric Reliability Corporation and Northeast Power Coordinating Council reliability standards. At a minimum, to ensure reliable operations, ISO-NE must procure sufficient resources to meet requirements for: (i) Ten-Minute Reserve, which comprises Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve; (ii) Total Thirty-Minute Operating Reserve, which comprises Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve; and, (iii) Replacement Reserve. ISO-NE has explicit requirements at the system level for Ten-Minute Spinning Reserve, Total Ten-Minute Reserve, and Total Thirty-Minute Operating Reserves, in addition to local requirements for Total Thirty-Minute Operating Reserve for the NEMA/Boston, Southwest Connecticut, and Connecticut zones.

In ISO-NE, reserves are priced in real-time based on the opportunity cost of providing reserves. Thus, resources do not explicitly offer reserves at specific prices, rather they offer to supply energy and/or reserves, and provide associated offer prices, and ISO-NE determines the optimal assignment of resources between supplying energy and reserves as well as energy and reserve prices that are consistent with that dispatch. In most intervals, reserve prices are zero since there are sufficient reserves available from offline capacity capable of providing operating reserves and unloaded online capacity such that there is no tradeoff between supplying energy and supplying reserves.

When there is a tradeoff between energy and reserves, the maximum redispatch cost ISO-NE will incur to create reserves is limited to the reserve constraint penalty factors, outlined in Table 13 below. The reserve constraint penalty factors also represent a price ceiling as to what ISO-NE will pay for reserves when it is physically short of reserves.

Table 13. ISO-NE Reserve Constraint Penalty Factors

Requirement	Price
Local Thirty-Minute Operating Reserve	$250
System Thirty-Minute Operating Reserve	$500
System Ten-Minute Non-Spinning Reserve	$850
System Ten-Minute Spinning Reserve	$50
Replacement Reserve	$250

Replacement Reserve

ISO-NE recently implemented a Replacement Reserve requirement of 160 MW in the summer and 180 MW in the winter to help resolve conditions where additional commitments are necessary to protect the system against normal system uncertainties and to avoid the need for emergency actions due to events such as load forecast errors, generator contingencies and reductions, and resource unavailability. ISO-NE will redispatch the system (but not take emergency actions) to maintain Replacement Reserve, the Replacement Reserve price, including the reserve constraint penalty factor.

Local Thirty-Minute Operating Reserve

If ISO-NE is short of Thirty-Minute Operating Reserve in any of the three Reserve Zones, the price for Local Thirty-Minute Operating Reserve in that zone will be $250/MWh.

System Thirty-Minute Operating Reserve

If ISO-NE is short of Total Thirty-Minute Operating Reserve but not Ten-Minute Reserve, the price for Thirty-Minute Operating Reserve will be $500/MWh, and the price for Ten-Minute Operating Reserve prices will be at least at that level, if not higher. Energy prices will also reflect this reserve constraint penalty factor unless the system is purely ramp-constrained and there is no tradeoff between supplying energy or reserves.[98]

System Ten-Minute Non-Spinning Reserve

The reserve constraint penalty factor for Ten-Minute Operating Reserve is either $850/MWh or $1,350/MWh depending on whether the system is short of Total Thirty-Minute Operating Reserve or just short of Ten-Minute Non-Spinning Reserve. Since ISO-NE has a Total Thirty-Minute Operating Reserve requirement, rather than an explicit Thirty-Minute Operating Reserve Requirement, even if ISO-NE is short of Ten-Minute Operating Reserve, it will still attempt to procure additional Thirty-Minute Operating Reserve, if available, to meet its Total Thirty-Minute Operating Reserve Requirement.

System Ten-Minute Spinning Reserve

If ISO-NE is carrying sufficient Total Ten-Minute Reserve and Total Thirty-Minute Operating Reserve, but less than its desired amount of Ten-Minute Spinning Reserve,[99] ISO-NE will attempt to create additional Ten-Minute Spinning Reserve subject to a price ceiling of $50/MWh. When the Ten-Minute Spinning Reserve constraint is binding (e.g.

[98] For the sake of simplicity, this example ignores the possibility of combinations of local reserve deficiencies combined with transmission constraints that can result in different pricing outcomes.

[99] ISO-NE typically carries at least half of its Total Ten-Minute Reserve Requirement as Ten-Minute Spinning Reserve, though that figure can go as low as twenty five percent depending on system conditions.

there is a positive price for Ten-Minute Spinning Reserve even though ISO-NE is meeting its Total Ten-Minute Reserve and Total Thirty-Minute Operating Reserve requirements), this additional cost will typically be reflected in the system energy price (LMP).

Regulation Reserve Shortage

ISO-NE's Regulation Capacity penalty factor is more complicated than the reserve constraint penalty factors used for other Operating Reserve products. For Regulation Capacity, there are two possible pricing impacts ($/MW): (a) if the energy component of the real-time locational marginal price is greater than or equal to $100/MWh, the penalty factor is $100/MW plus the energy component of the real-time locational marginal price for each megawatt of Regulation Capacity shortfall, and (b) if the energy component of the real-time locational marginal price is less than $100/MWh, the penalty factor is the maximum of either zero or $100 plus the energy component of the real-time locational marginal price for each megawatt of Regulation Capacity shortfall. The Regulation Mileage penalty factor is $10/MW for each megawatt of Regulation Service shortfall; in addition, selection will consider opportunity cost sensitivities associated with large changes in the estimated opportunity cost of a Resource due to the shape of the resource's supply offer price curve.

Energy Shortage

The energy offer cap is $1,000/MWh, so in a shortage energy prices should reach that level,[100] and may also reflect the reserve constraint penalty factors for shortages of System Ten-Minute Reserve and System Thirty-Minute Operating Reserve if those products are short as well, so (the energy component of) energy prices could reach $2,350/MWh during an energy shortage ($1000 + $850 + $500).

[100] The energy component of LMP should reach $1,000/MWh. Losses and congestion energy prices may lead to LMP at any location exceeding or falling short of $1,000/MWh.

Appendix 3 Midcontinent Independent System Operator, Inc. (MISO)

Shortage Definition

MISO defines a shortage as any time the sum of demand bids, fixed export schedules, system losses, and operating reserve requirements in the day-ahead energy and ancillary services market cannot be met by the maximum supply level of all available non-emergency resources, import schedules, and virtual supply offers. Shortages can occur either on a MISO-wide basis or a zonal basis.[101]

If MISO anticipates or is experiencing a shortage of operating reserves in the day-ahead market, it will commit generation resources up to the emergency limits of market participants' offers to supply, demand response resources type II, and external asynchronous resources.[102] MISO will also commit generation resources, Demand Response Resources Type I, and Demand Response Resources Type II that are designated as emergency-only to levels necessary to relieve the shortage in an economic manner.[103] If operating reserves are depleted and energy demand cannot be met, MISO will then curtail fixed demand bids and fixed export schedules.

In the real-time market, MISO's rules governing a shortage are similar to those followed in the day-ahead period. In the case of a shortage of operating reserve, MISO will take the additional step of curtailing exports schedules in amounts sufficient to relieve the shortage in an economic manner.[104] If these actions are not sufficient to relieve the shortage, MISO must then call an Emergency Energy Alert 1 (EEA1). If MISO deems the shortage to be significant, it can declare Emergency Energy Alert 2 (EEA2).[105]

Declaring EEA2 provides MISO with further steps it may take to mitigate any shortage, including: (1) directing load serving entities to curtail appropriate amounts of Load Modifying Resources (a type of demand response resource); (2) dispatching emergency demand response based on submitted offers; (3) purchasing emergency energy; (4)

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[101] MISO's current seven reserve zones are or incorporate parts of (approximately) Indiana; Illinois, Missouri, Iowa, Arkansas, Louisiana, and Mississippi; the lower peninsula of Michigan; Wisconsin and the upper peninsula of Michigan; Iowa, Minnesota, and North Dakota; southeast Louisiana; and, Texas.

[102] This does not include resources committed to provide Regulation service, which must be kept at a set-point below their maximum in order to continue to provide Regulation service.

[103] MISO, Tariff, Module C Energy and Operating Reserves, at § 39.2.10 (Shortage Conditions in the Day-Ahead Energy and Operating Reserve Markets).

[104] MISO, Tariff, Module C Energy and Operating Reserves, at § 40.2.20 (Capacity Shortage in the Real-Time Energy and Operating Reserve Market).

[105] *Id*.

issuing a public appeal to reduce demand; and, (5) directing local Balancing Authorities to implement a voltage reduction.[106]

Shortage Pricing

When a shortage of operating reserves occurs, whether MISO-wide or on a zonal basis, and none of the steps described above alleviate the problem, MISO's tariff states that energy locational marginal prices and operating reserve market-clearing prices are determined using the Security-Constrained Economic Dispatch algorithm which incorporates shortage pricing based on Operating Reserve Demand Curves, Regulation and Spinning Reserve Demand Curves, and Regulating Reserve Demand Curves.[107] These demand curves apply to three different (worsening) scenarios that can occur alone or in combination. MISO defines four products that it, as the system operator, procures: locational energy, Regulating Reserve, Spinning Reserve, and Supplemental Reserve.[108] Regulating Reserve may substitute for Spinning Reserve because it is a higher quality product, but not vice-versa. Similarly, Spinning Reserve may substitute for Supplemental Reserve, but not vice-versa. [109]

MISO uses a combination of negatively-sloped demand curves and administrative prices to establish the energy LMP and operating reserve market-clearing prices, as summarized in Table 14 below. Many of these hinge on MISO's Value of Lost Load, the estimated value that consumers put on losing power, and the probability of losing load if a shortage in Operating Reserve is exacerbated by a further contingency. Value of Lost Load in MISO is currently set at $3500/MWh.

Operating Reserve Demand Curve (i.e. the combination of all reserve products)

If MISO experiences a region-wide shortage of the Operating Reserve requirement, it will set the market-clearing price for all operating reserves at a level dependent on the degree of shortage.[110] The market-clearing price starts at $200/MWh if MISO is able to clear 96 percent or more of the requirement. If MISO is able to clear less than 4 percent

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[106] MISO, *Market Capacity Emergency Procedures RTO-EOP-002-r17* (effective June 1, 2014), *available at* https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=177019.

[107] MISO, Tariff, Module C Energy and Operating Reserves, at § 39.2.10 (Shortage Conditions in the Day-Ahead Energy and Operating Reserve Markets).

[108] MISO, Business Practice Manual 002 Energy and Operating Reserve Markets at 43.

[109] *Id.* at 46, 190.

[110] Operating Reserve demand curves for zonal shortages are similar, with slight changes in the exact numbers.

of the requirement, the market-clearing price is set at the Value of Lost Load, or $3500/MWh, minus the maximum market-wide Regulating Reserve demand curve price for that month. For any amount cleared at least 4 percent but less than 96 percent then the market-clearing price is a function of the product of Value of Lost Load and the probability that there will be a loss of load due to single forced resource outage of 100 MW or greater.

When MISO experiences a zonal shortage of the operating reserves requirement, if the market operator is able to clear 80 percent or more of the requirement, the market-clearing prices for all operating reserve products is set equal to $200/MWh. If MISO is able to clear less than 10 percent of the requirement, the market-clearing price is set equal to the Value of Lost Load minus the reserve zone's maximum Regulating Reserve Demand Curve Scarcity Price. For any amount cleared at least 10 percent but less than 80 percent of the requirement, the market-clearing price is set equal to the sum of the Energy Offer Price Cap ($1000/MWh) and the Contingency Reserve Offer Price Cap ($100).

Table 14. MISO Shortage Pricing

Product Shortage	Price
MISO-wide Operating Reserve	Min. $200/MWh to Max. VOLL ($3500/MWh) minus Regulating Reserve demand curve value, depending on level of shortage.
MISO-wide Spinning and Regulating Reserves	Min. $65/MWh to Max. $98/MWh depending on level of shortage.
MISO-wide Regulating Reserve	Max. of (i) Contingency Reserve Offer Cap and (ii) Peaker Commitment Cost for one hour.
MISO-wide Energy	LMP set to Value of Lost Load ($3500/MWh).
Reserve Zone Operating Reserve	Min. $200/Mwh to Max. VOLL ($3500/MWh) minus maximum Regulating Reserve Demand Curve Scarcity Price.
Reserve Zone Spinning and Regulating Reserves	$65/MWh if > 90% of requirement. $98/Mwh if < 90% of requirement.
Reserve Zone Regulating Reserve	Max. of (i) Contingency Reserve Offer Cap and (ii) Peaker Commitment Cost for one hour.

Regulating and Spinning Reserves Demand Curve

If MISO experiences a region-wide or zonal shortage of Regulation and Spinning Reserves, it will set the market-clearing prices for both Spinning Reserve and Regulating Reserve at a level dependent on the degree of shortage. The market-clearing price starts at $65/MWh if MISO is able to clear more than 90 percent of the requirement. If MISO is able to clear less than 90 percent of the requirement, the market-clearing price is set at \$98/MWh.[111] There is no impact on the market-clearing price for Supplemental Reserve.

Regulating Reserve shortage

If MISO experiences a region-wide or zonal shortage of Regulating Reserve, the market-clearing price for Regulating Reserve will be set equal to the maximum of either the Contingency Reserve Offer Cap or the average cost per MWh of committing and running a peaker unit for one hour. MISO defines three different types of Regulating Reserve shortages: (i) a shortage of Regulating Reserve in the upward direction; (ii) a shortage of Regulating Reserve in the downward direction; and (iii) a shortage of resources with Regulation Capability. In the first case, a Regulation Up shortage, shortage prices will impact energy LMP but not Spinning or Supplemental Reserve market-clearing prices. In the case of a Regulation Down shortage, energy LMP will be effected negatively and there is no impact on Spinning or Supplemental Reserve market-clearing prices. If there is a shortage of regulation-qualified resources, because this is not considered a capacity shortage, it only impacts the Regulating Reserve market-clearing price.

Energy Shortage

In the event that operating reserves are depleted and energy demand cannot be met, all energy and operating reserves will be priced at the Value of Lost Load, currently set at \$3500/MWh.[112]

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[111] MISO, Tariff, Schedule 28 (Operating Reserve Demand Curves). Schedule 28 specifies these price levels for quantities less than 90 percent and greater than 90 percent (omitting 90 percent exactly).

[112] MISO, Tariff, Module C Energy and Operating Reserves at § 39.2.10 (Shortage Conditions in the Day-Ahead Energy and Operating Reserve Markets).

Appendix 4 New York Independent System Operator, Inc. (NYISO)

Shortage Definition

NYISO has a comprehensive set of pricing rules during shortage conditions when NYISO has run short of Regulation, Ten-Minute Reserve, Thirty-Minute Reserve, and/or Spinning Reserve for the entire ISO, or for either of two defined subzones. NYISO also has rules and procedures to address and avoid shortages before they occur in real-time. NYISO denotes the entire ISO as the New York Control Area; the subzones are East of Central East, which includes New York City and Long Island, and Long Island (LI), which is a separate subzone within East of Central East.

If NYISO's Security Constrained Unit Commitment program indicates that NYISO will be short of operating reserves in the Day-Ahead market, or if Security Constrained Unit Commitment has already been completed and conditions then change such that the revised day-ahead forecast indicates there will be an operating reserve deficiency, NYISO will take the following actions as needed to relieve the deficiency: (i) commit/schedule additional generation from the set of unaccepted/uncommitted bids; (ii) request additional generation bids from market participants; (iii) count the energy associated with external resources with a New York Control Area Installed Capacity commitment as well as external energy sales by New York Control Area Installed Capacity resources as operating reserves; (iv) inform market participants that their generation may be dispatched to Upper Operating Limit Emergency levels the following day; and, (v) notify the appropriate market participants to prepare to make Special Case Resources and Emergency Demand Response Program resources available for the next day. In addition, should these actions be insufficient, NYISO may request that Transmission Owners (a) notify interruptible customers to make interruptible load available for curtailment for the next day; (b) prepare to initiate procedures to reduce voltage by 5 percent if they have Manual Voltage Reduction equipment; (c) contact large commercial and industrial customers to voluntarily curtail load; (d) make public appeals; and, (e) count load reductions that can be can be implemented within 10 minutes using Quick Response Voltage Reduction as NYISO Ten-Minute Reserve.[113]

If there is still a shortage in real-time, NYISO will attempt to preserve Ten-Minute Synchronized Reserve by converting Ten- and Thirty-Minute Non-Synchronized Reserves to Ten-Minute Synchronized Reserve or energy, activating the use of generating resources' Upper Operating Limit Emergency limits, curtailing exports, counting load reduction available from Quick Response Voltage Reduction as Ten-Minute Reserve, and purchasing emergency energy from resources outside of NYISO.

Shortage Pricing

[113] NYISO, Manual 15 Emergency Operations Manual, at 4-5 to 4-8.

Whatever actions the NYISO operator takes to avert an operating reserve deficiency, NYISO's shortage pricing is triggered whenever NYISO runs short of Regulation, Ten-Minute Reserve, Thirty-Minute Reserve, or Spinning Reserve for the entire ISO or for its two defined subzones. NYISO's administrative shortage prices are shown in Table 15 below.

Table 15. NYISO Shortage Pricing[114]

Service	Shortfall	New York Control Area	East of CE (New York City or Long Island)	Long Island only
Regulation	0 to 25	80	n/a	n/a
	> 25 to 80	180	n/a	n/a
	> 80	400	n/a	n/a
Thirty-Minute	0 to 200	50	25	25
	> 200 to 400	100	25	25
	> 400	200	25	25
Total Ten-Minute	> 0	450	500	25
Total Spinning	> 0	500	25	25

If a shortage occurs in the New York Control Area, the market-clearing price is set as indicated in the "New York Control Area" column. For instance, if the New York Control Area is more than 400 MW deficient in Thirty-Minute Reserve, the market-clearing price for Thirty-Minute Reserve would be $200/MWh. In addition, the values are additive when there is a deficiency of multiple products: if the New York Control Area is short of both Thirty-Minute and Ten-Minute Reserve, that would result in a market-clearing price for Thirty-Minute Reserve in the New York Control Area of $200/MWh (assuming it is deficient more than 400 MW) and the market-clearing price for Ten-Minute Reserve would be at least $500/MWh (equal to the shortage price for Ten-Minute Reserve plus the shortage price for being deficient less than 200 MW of Thirty-Minute Reserve) to a maximum of $650/MWh (equal to the shortage price for Ten-Minute Reserve plus the shortage price for being deficient more than 400 MW of Thirty-Minute Reserve).

Similarly, if the shortage occurs just in the East of Central East area or just in the Long Island area the market-clearing prices are set as indicated in the East of Central East

[114] NYISO, Market Services Tariff, §§ 15.3.7, 15.4.7.

column or the “Long Island” column, respectively. Prices in each subzone will also reflect administrative price in larger zones. For instance, prices in the East of Central East area, which is nested within the New York Control Area zone, will also reflect administrative prices in the New York Control Area. Prices in Long Island, which is nested in both the East of Central East and the New York Control Area zones, will reflect administrative prices in East of Central East and the New York Control Area, as applicable to the situation.

Regulation

Regulation in NYISO is procured region-wide and shortage prices are defined by a stepped demand curve: Regulation prices will be $80/MWh if there is a shortfall of between 0 and 25 MW, $180/MWh for a shortfall greater than 25 MW up to 80 MW, and $400/MWh for a shortage greater than 80 MW.

Thirty-Minute Operating Reserve

Shortages of Thirty-Minute Operating Reserve are also subject to a stepped demand curve: $50 for 0 to 200 MW, $100 for greater than 200 MW up to 400 MW and $200/MWh if the shortage is greater than 400 MW. If the shortage is in the East of Central East zone, prices are $25/MWh higher in every case, and are $50/MWh ($25 plus $25) higher if the shortage is in the Long Island zone.

Total Ten-Minute Reserve

Any shortage of Total Ten-Minute Reserve is priced at $450/MWh in the New York Control Area (rest of state) zone, an additional $500/MWh if East of Central East is also short of Ten-Minute Reserve ($950/MWh) and an additional $25/MWh is Long Island if short as well ($975/MWh).

Spinning Reserve

Any shortage of Spinning Reserve is priced at $500/MWh in the New York Control Area (rest of state) zone, an additional $25/MWh if East of Central East is also short of Ten-Minute Reserves ($525/MWh) and an additional $25/MWh is Long Island if short as well ($550/MWh).

Energy Shortage

NYISO also fully co-optimizes energy and reserves. The energy offer cap is $1,000/MWh, so in a shortage energy prices should reach that level, and may also rise to higher price levels to reflect the additional shortage prices for Thirty-Minute Operating Reserve, Ten-Minute Operating Reserve, Spinning Reserve, and any locational shortage price. Thus, a shortage of energy on Long Island could yield energy prices of up to $2775/MWh[115] if the New York Control Area, East of Central East, and Long Island are all also short of Ten-Minute Reserve, Total Operating Reserve, and Total Spinning Reserve.

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[115] $2775=$1000 (energy) + $250 (Thirty-Minute Reserve system-wide and zonal) + $975 (Ten-Minute Reserve system-wide and zonal) + $550 (Spinning system-wide and zonal).

Appendix 5 PJM Interconnection, L.L.C. (PJM)

Shortage Definition

PJM defines a reserve shortage as a situation in which the dispatch software is unable to obtain the required reserves in a particular reserve region at a price less than the reserve shortage penalty factor. Shortage pricing is based on a forecast of a shortage in the real-time commitment period so it is possible that shortage pricing might occur without an actual shortage happening.

If, after real-time commitment, the system operator still anticipates a shortage, the options that the dispatcher can use to avert a shortage are limited. The dispatcher can issue a warning to units to be aware of the impending shortage and to PJM management who can then issue messages to the public to conserve energy. After a shortage begins, the dispatcher can invoke the emergency range on generators which can give some more capacity. Also, after a shortage begins, the dispatcher can invoke region-wide emergency demand response.

Load shedding and voltage drops at the nodal level results in shortage pricing equivalent to a Synchronous Reserve shortage at that node.[116]

Shortage Pricing

PJM invokes shortage pricing whenever the dispatch software cannot meet the primary reserve requirement. The primary reserve requirement is the sum of the Synchronous Reserve requirement and the Non-Synchronous Reserve requirement. An additional shortage price is added when the Synchronous Reserve requirement cannot be satisfied. These are the only shortage prices in PJM.

As in the other RTOs, the energy LMP and operating reserve market-clearing prices would also account for the opportunity cost of missing out on an operating reserve price equal to the relevant shortage prices.

[116] PJM, Manual 11 Energy & Ancillary Services Market Operations.

Table 16. PJM Shortage Pricing

Product Shortage	Price/Penalty Factor
Synchronous Reserve	$550/MWh
Non-Synchronous Reserve	$550/MWh
Regulation	n/a
Voltage Drop	$2100 = $1000/MWh + Synchronous and Non-Synchronous penalties ($1100)
Energy	$2100 = $1000/MWh + Synchronous and Non-Synchronous penalties ($1100)

Primary Reserve Demand Curve (i.e. Non-Synchronous Reserve and/or Synchronous Reserve requirements cannot be met)

The Primary Reserve demand curve accounts for PJM's ability to meet both its Non-Synchronous Reserve and Synchronous Reserve requirements and is a stepped demand curve with two vertical jumps. The first step is at a quantity equal to the sum of the Non-Synchronous Reserve requirement plus the Synchronous Reserve requirement, where the demand curve rises to the Non-Synchronous Reserve penalty factor, currently set at $550/MWh. The second step is at the Synchronous Reserve requirement (*i.e.*, if this point is passed, PJM has procured no Non-Synchronous Reserve and cannot meet the Synchronous Reserve requirement either) and the demand curve rises to the sum of the Synchronous Reserve penalty factor, also currently $550/MWh, and the Primary Reserve penalty factor, or $1100/MWh.

Regulating Reserve Demand

If PJM runs short of ordinary Regulation Reserve, it uses Synchronous Reserve and treats them as regulation resources to the best of their ability. PJM does not have a Regulation Reserve shortage price. Using Synchronous Reserve as Regulation is considered a "spinning event" in PJM but these events are not shortage events and typically do not result in high Synchronous Reserve prices.

Spinning events in PJM can occur when there is a generator outage, a transmission outage, or a shortage of Regulation Reserve. There were 16 spinning events in PJM in 2013. Most of these events were very brief: eight of these were 10 minutes or less in duration. The external market monitor did not say what caused each spinning event but did say the longest spinning event, which occurred on September 10, 2013, and lasted 68 minutes, was caused by a shortage of Regulation Reserve. The Spinning Reserve price during this event was $0/MWh; therefore, a shortage in Regulation Reserve has no direct relationship to the Spinning Reserve price.[117]

Energy Shortage or Voltage drop

If PJM institutes a voltage drop or is forced to shed load, the penalty factor in the affected area will be the same as a Synchronous Reserve shortage and would currently be $800/MWh. Emergency demand response, when called upon, leads to the highest possible energy price, which is currently set at $2100 per MWh.[118]

[117] Monitoring Analytics, LLC, *State of the Market for PJM* at 313 (Mar. 13, 2014), *available at* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013-som-pjm-volume1.pdf.

[118] *See, e.g.*, PJM, Operating Agreement, Sch. 1, § 3.2.3A.001(c).

Appendix 6 Southwest Power Pool, Inc. (SPP)

Shortage Definition

SPP defines shortage prices as the market-clearing prices and locational market price levels when there is insufficient operating reserve available to meet the operating reserve requirements.[119] SPP further defines multiple scenarios under which a shortage can occur.

SPP defines its operating reserves as Regulation-Up, Regulation-Down, and Contingency Reserve (which includes Spinning Reserve and Supplemental Reserve). SPP uses the term operating reserve to refer to these as a group. Finally, SPP also defines Ready Reserve, a reserve product seemingly less valuable than spinning reserve, possibly the same as Supplemental Reserve.

SPP's tariff outlines steps that must be taken in order to avert a shortage. Specifically, SPP's tariff specifies that, in order, non-firm fixed exports will be curtailed, and, if necessary, resources will be committed to their maximum generating limits and/or emergency-only resources will be committed. These steps occur automatically within the day-ahead security-constrained unit dispatch. If these steps do not resolve the problem, the system operator may manually commit emergency-only designated units.[120]

Shortage Pricing

SPP applies values derived from various shortage pricing schedules to set market-clearing prices during a shortage of operating reserves, as shown in Table 17. These apply in both the day-ahead and real-time markets, and also apply on both a system-wide and a reserve zone basis. Shortage pricing values are based on defined offer caps for energy and the operating reserve products, depending on the specific shortage. If an operating reserve shortage is caused by insufficient ramping ability, SPP does not institute shortage pricing.[121]

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[119] SPP, Tariff, attach. AE, §1.1 Definitions S. The tariff provisions described here have only been effective since March 1, 2014. Prior to this time SPP was a real-time-only balancing market comprising 16 separate Balancing Authority Areas. Each Balancing Authority Area was responsible for maintaining reserves.

[120] SPP, Tariff, attach. AE, § 5.1.2(1). It is possible for a resource owner to choose an emergency-only dispatch status that allows the system operator to commit the resource only to alleviate an anticipated emergency condition or local reliability issue. SPP Tariff, attach. AE, § 4.1(10).

[121] *See* SPP, Tariff, attach. AE, § 8.3.4.2.

Table 17. SPP System-Wide Shortage Pricing

Requirement	Market-Clearing Price
Supplemental Reserve	\$1100 + Zonal Regulation-Up plus Contingency Reserve Shadow Price
Spinning Reserve	\$200 + Supplemental Reserve MCP + Zonal Regulation-Up plus Contingency Reserve Shadow Price
Regulation-Up Reserve	\$600 + Spinning Reserve MCP + Zonal Regulation-Up Shadow Price
Regulation-Down Reserve	\$600
Energy	LMP accounts for all Shortage-Priced MCPs with a maximum = \$50,000.

System-wide Contingency Reserve requirement cannot be met; Regulation-Up and Regulation-Down Reserve requirements can be met and zonal requirements can be met[122]

In the event that SPP cannot meet its contingency reserve requirement, the market-clearing price for Supplemental Reserve is set equal to the sum of the shortage prices of the system-wide Regulation-Up plus Contingency Reserve constraint and the zonal Regulation-Up plus Contingency Reserve constraint. The system-wide shortage price for the Regulation-Up plus Contingency Reserve constraint is set equal to the Operating Reserve Demand Curve, which is defined as the sum of the safety-net energy offer cap (\$1000) plus the Contingency Reserve offer cap (\$100), or \$1100. The Spinning Reserve market-clearing price is set equal to the sum of: (i) Supplemental Reserve market-clearing price; (ii) the system-wide Regulation-Up plus Spinning Reserve constraint shortage price; and, (iii) the zonal Regulation-Up plus Spinning Reserve constraint shortage price. While this appears to be a complex calculation, in reality this simply means that the value is calculated as normal except that a resource's opportunity cost for providing Spinning Reserve must include the \$1100 system-wide shortage price due to that shortage. Also, if the Spinning Reserve requirement cannot be met, the value of the shortage price on the Regulation-Up plus Spinning Reserve is set to \$200.[123] Similarly, SPP's Regulation-Up market-clearing price under this scenario would be equal to the sum of: (i) Spinning Reserve market-clearing price; (ii) system-wide Regulation-Up constraint shortage price; and, (iii) the zonal Regulation-Up constraint shortage price. Again, the Regulation-Up market-clearing price would include the opportunity cost of

[122] SPP defines a shortage of Contingency Reserves (Spinning plus Supplemental Reserves), but does not define a shortage specifically of Spinning Reserve while being able to meet its supplemental reserve requirement.

[123] SPP, Tariff, attach. AE, Addendum 1 Violation Relaxation Limit Values.

providing Regulation-Up (rather than Spinning or Supplemental Reserves) and so the $1100 filters through to this market-clearing price as well.

System-wide Contingency Reserve and Regulation-Up Reserve requirements cannot be met; Regulation-Down and zonal requirements can be met

If SPP is short of both contingency reserves and Regulation-Up, the Supplemental Reserve market-clearing price and Spinning Reserve market-clearing price are calculated as described above. The Regulation-Up market-clearing price is calculated slightly differently now, however, because this product is also experiencing a shortage. The Regulation-Up market-clearing price is equal to the sum of: (i) Spinning Reserve market-clearing price; (ii) the system-wide Regulation-Up shortage price; and, (iii) the zonal Regulation-Up shortage price; the shortage price of system-wide Regulation-Up is equal to the sum of the Regulation offer cap ($500) plus the Contingency Reserve offer cap ($100), or $600.

System-wide Contingency Reserves requirement cannot be met, and zonal minimum requirements cannot be met; all other requirements can be met

This scenario mimics the first one presented for SPP, except that in addition, the system operator cannot meet the zonal minimum requirements. In those zones where the minimum requirement has not been met, shortage pricing is instituted. For instance, if the zonal requirement is not met, then the zonal constraint shortage price is also set to $1100 and the Supplemental Reserve market-clearing price in that zone is equal to $2200. This price would then filter through (via the opportunity cost calculation) to the market-clearing prices for the other reserve products (except Regulation-Down). If a zone is unable to meet its Spinning Reserve requirement, shortage pricing would be invoked for just that zone for Spinning Reserve.

System-wide Contingency Reserve requirement and Regulation-Up requirement cannot be met, and zonal minimum requirements cannot be met; the Regulation-Down requirement can be met

In this instance, market-clearing prices for Supplemental and Spinning Reserves are calculated as described in the preceding section and the market-clearing price for Regulation-Up will directly include that shortage price ($600, as described above). Again, the invocation of zonal shortage prices will only occur in those zones unable to meet their individual requirements.

System-wide Regulation-Up requirement cannot be met, all other minimum requirements (including zonal) can be met

In this instance, only one reserve product, Regulation-Up, is short. Because Regulation-Up is the most valuable product and Spinning and Supplemental Reserves cannot substitute for it, only the market-clearing price for Regulation-Up and the energy LMP are impacted by shortage pricing. In this instance, the system-wide market-clearing price for Regulation-Up will equal the sum of: (i) Spinning Reserve market-clearing price; (ii) system-wide Regulation-Up shortage price; and, (iii) the zonal Regulation-Up shortage price. The only term in this equation that reflects shortage pricing is the second, which would be equal to $600.

System-wide Regulation-Down requirement cannot be met; all other requirements are met.

In this instance, none of the other reserve products are impacted by shortage pricing. Because there is no substitutability between Regulation-Down and the other products, there are no opportunity costs to account for and the market-clearing price for Regulation-Down is set equal to $600.

Energy Shortage

In each of the instance described above, the energy LMP will reflect, through opportunity costs, the shortage pricing effects imposed under the different scenarios. However, if SPP is short of all reserve products and is forced to short energy (i.e. shed load), the LMP will be calculated, explicitly accounting for each (additive) shortage price currently in effect. Further, SPP maintains a $50,000/MW "Global Power Balance" Violation Relaxation Limit, meaning it will redispatch its system no matter the cost, up to and including $50,000/MW in order to avoid load-shedding due to a lack of energy available to balance resources and load.

Appendix 7 Electric Reliability Council of Texas (ERCOT)

Shortage Definition

ERCOT is required to maintain at least between 2300 MW and 2800 MW of Physical Responsive Capability, depending on the level of wind on the system. Of this amount, up to half can be supplied by Interruptible Responsive Reserve which is provided by Load Resources that are automatically interrupted when system frequency decreases to 59.7 Hz. The remaining requirement is met by both Synchronized and Non-Synchronized Reserves. In addition to these reserves, ERCOT also procures Regulation-Up and Regulation-Down Reserves and Non-Spinning Reserve Service. Regulation-Up can serve to offset part of ERCOT's Non-Spinning Reserve Service requirement. ERCOT enters into an Energy Emergency Alert (EEA) whenever it is unable to meet its minimum requirements for Physical Responsive Capability.

In order to avoid EEA conditions, ERCOT may take certain operator actions. ERCOT will issue an Operating Condition Notice to inform all Qualified Scheduling Entities of a possible future need for more Resources due to conditions that could affect ERCOT System reliability.[124] If Physical Responsive Capability falls below 3000 MW, ERCOT can issue an Advisory which allows it to exercise its authority, in such circumstances, to increase operating reserve requirements above the quantities originally specified in the Day-Ahead in accordance with procedures and may require information from Qualified Scheduling Entities representing Resources regarding the Resources' fuel capabilities. ERCOT may also issue an appeal through the public news media for voluntary energy conservation.[125] If Physical Responsive Capability falls below 2500 MW, ERCOT can issue a Watch and may immediately procure Regulation Services; Responsive Reserves Services and Non-Spin services from existing offers. ERCOT may also issue Dispatch Instructions to Resources certified to provide the insufficient service, even though there is not an existing operating reserve offer for that resource.[126]

If Physical Responsive Capability falls below ERCOT's minimum requirement (2300 to 2800 MW), ERCOT will declare an Energy Emergency Alert Level 1. During EEA Level 1, ERCOT will request available Generation Resources that can perform within the expected timeframe of the emergency to come On-Line by initiating manual commitment or through Dispatch Instruction; use available DC Tie import capacity not already being used; issue a Dispatch Instruction for Resources to remain On-Line which, before start of

[124] ERCOT, Nodal Protocols, § 6.5.9.3.1 (Operating Condition Notice).

[125] ERCOT, Operating Procedure Manual, Transmission and Security Desk V1Rev31, § 4.9 (Responding to Diminishing Reserves); ERCOT, Nodal Protocols, § 6.5.9.3.2 (Advisory).

[126] ERCOT, Operating Procedure Manual, Transmission and Security Desk V1Rev31, § 4.9 (Responding to Diminishing Reserves); ERCOT, Nodal Protocols, § 6.5.9.3.3 (Watch).

emergency, were scheduled to come Off-Line; and at ERCOT's discretion, deploy available contracted Emergency Response Service loads with a 30-minute ramp period.[127]

If Physical Responsive Capability falls below 1750 MW, ERCOT will declare an EEA Level 2. Under EEA Level 2, ERCOT will instruct transmission and distribution service providers to reduce Customers' Load by using distribution voltage reduction measures, instruct Qualified Scheduling Entities to deploy Emergency Response Service with 10-minute ramp periods, and deploy Responsive Reserves Services capacity supplied by Load Resources.[128]

If Physical Responsive Capability continues to drop or ERCOT is unable to maintain a frequency of 59.8 Hz, ERCOT will implement EEA Level 3, which requires transmission and distribution service provides to shed firm load in 100 MW blocks until the system can maintain 59.8 Hz.[129]

Shortage Pricing

Depending on the level of deficiency and actions taken, as described above, two shortage pricing methods can come into effect. ERCOT implements administrative shortage pricing when their Security Constrained Economic Dispatch software needs to dispatch regulation resources to provide energy in order to maintain power balance (rather than to provide Regulation Reserve). This administrative pricing is referred to as the Power Balance Penalty Curve and it acts as if it were an energy offer curve for a virtual Generation Resource injecting the amount of the Power Balance mismatch into the ERCOT system.[130]

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[127] ERCOT, Nodal Protocols, § 6.5.9.4.2 (EEA Levels).

[128] *Id.*

[129] *Id.*

[130] ERCOT Business Practice, Setting the Shadow Price Caps and Power Balance Penalties in Security Constrained Economic Dispatch, at 20-21(April 18, 2014).

Table 18. ERCOT Power Balance Penalty Curve[131]

MW Violation	Price/MWh
≤ 5	$250
5 < to ≤ 10	$300
10 < to ≤ 20	$400
20 < to ≤ 30	$500
30 < to ≤ 40	$1,000
40 < to ≤ 50	$2,250
50 < to ≤ 100	$3,400
100 < to ≤ 150	$4,600
150 < to ≤ 200	$5,800
200 or more	$7,001

On June 1, 2014, ERCOT implemented an Operating Reserve Demand Curve which is used both to price reserves and as a price adder to the real-time energy price. The Operating Reserve Demand Curve is designed to ensure that reserve and energy prices reflect the likelihood that ERCOT will have to shed firm load, measured by the Loss of Load Probability, which can vary from hour-to-hour or day-to-day, and the value of shedding that firm load, the Value of Lost Load. The Operating Reserve Demand Curve ORDC adder therefore is computed as (Value of Lost Load – energy price) * Loss of Load Probability. This curve slopes upwards starting at 5000 MW of reserves before becoming vertical at 2,000 MW and is capped at Value of Lost Load, which is currently set at $9000.[132] . The minimum contingency level of 2000 MW reflects the belief that at this point the probability of losing load is so large that prices must be increased to Value of Lost Load.[133]

Shortage Pricing Events

Table 19 shows that shortage pricing in ERCOT is rare and that shortage pricing was much more prevalent in 2011 than any time since. Given ERCOT's pricing rules, LMPs in excess of $3000/MWh can be expected to reflect shortage pricing for the entire

[131] *Id.* at 25-26.

[132] *See* ERCOT, *Market Training, Operating Reserve Demand Curve Workshop* at 9 (2014), *available at* http://www.ercot.com/content/wcm/training_courses/107/ordc_workshop.pdf.

[133] ERCOT, *Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Market Adder*, at 2, *available at* http://ercot.com/content/mktinfo/rtm/kd/Methodology_for_Implementing_Operating_Reserve_Demand_Curve_.doc.

hour.[134] LMPs in excess of $2000/MWh probably reflect shortage pricing for several five minute intervals but not for the entire hour and LMPs in excess of $1000/MWh reflect shortage pricing for a few five minute intervals.

Table 19. ERCOT Number of Hours with High LMP, 2011—2014[135]

	2011	2012	2013	2014	All Years
> $3000 all zones	9	0	0	1	10
> $2000 all zones	14	2	1	1	18
> $1000 all zones	8	2	2	2	14
> $1000 zones 1-3	3	0	2	1	6
> $1000 total	34	4	5	5	48

[134] The one hour of high LMPs in 2014 were in excess of $4500/MWh.

[135] Data Source: Ventyx.