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November 26, 2024

VIA ELECTRONIC FILING

The Honorable Debbie-Anne Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Midcontinent Independent System Operator, Inc.'s Tariff Revisions On Value of Lost Load, Operating Reserve Demand Curve, and Emergency Demand Response Resources
Docket No. ER25-___-000

Dear Secretary Reese:

The Midcontinent Independent System Operator, Inc. ("MISO"), through this filing,[1] submits proposed revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"),[2] to update and improve the rules governing Value of Lost Load ("VOLL"), Demand Curves for Operating Reserves (hereinafter also referred to as "Operating Reserve Demand Curves" or "ORDC"), and Emergency Demand Response ("EDR") Resources, in MISO's Day-Ahead Energy and Operating Reserve Market ("Day-Ahead Market") and Real-Time Energy and Operating Reserve Market ("Real-Time Market").

MISO requests that these Tariff revisions be made effective for Operating Day September 30, 2025, to give MISO adequate time to design, test and implement software and complete other operational adjustments needed to implement the proposed changes regarding VOLL, ORDC, and EDRs. In addition, MISO requests expedited resolution of the proposed Tariff revisions by April 1, 2025, so that MISO can budget and prepare in advance for such software and other adjustments to ensure readiness to implement those revisions by September 30, 2025. MISO requests an extended comment period of forty-five (45) days in recognition of the upcoming holiday season and to facilitate stakeholders' review and comment on this proposal.

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[1] This filing is made pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 35.1, *et seq.*

[2] Unless otherwise indicated by the text or context of this transmittal letter, all terms used herein have the definitions set forth in Module A of the Tariff.

I. EXECUTIVE SUMMARY

MISO introduced the Reliability Imperative framework in 2020 to address the urgent and complex challenges to electric system reliability in the MISO region. The Reliability Imperative denotes and integrates the range of efforts MISO is pursuing, in consultation with its member utilities, and the state regulators within its footprint, to explore and make timely system and operational adjustments needed to ensure the system remains reliable as the region's resource mix changes. One of the four "Pillars" of the Reliability Imperative is Market Redefinition, which seeks to enhance and optimize MISO's markets to ensure continued reliability and efficiency while enabling the changing resource mix, responding to more frequent extreme weather events, preparing for increasing electrification and ensuring accurate pricing of energy and reserves. The proposed Tariff revisions are part of the Market Redefinition pillar. The proposed shortage pricing improvements will establish appropriate price signals before and during reserve shortage conditions to increase energy production and reduce consumption.

VOLL represents the price that demand is willing to pay to avoid loss of service. Currently, MISO's Tariff defines the VOLL to be $3,500/MWh, which is both a price cap, and an administrative price under severe Capacity shortage conditions. This VOLL value was established at the launch of MISO's Ancillary Services Market in 2009 and has not been updated since. As such, it is necessary and appropriate to update the VOLL and ORDC, and decouple the EDR offer cap from the updated VOLL.

In this filing, MISO proposes to distinguish two kinds of VOLL: (1) a Pricing VOLL of $10,000/MWh to be used as a price cap and an administrative price; and (2) a System VOLL of $35,000/MWh to be used to scale the ORDC. The two VOLL values have different functions. The Pricing VOLL represents the price consumers are willing to pay to avoid an interruption of electrical service, and is mainly based on consumers with the lowest willingness to pay. This Pricing VOLL is appropriate to use as a price cap (at all times) and also for fixed administrative pricing during emergencies when it is necessary to shed load. MISO also proposes a "circuit breaker" mechanism for reducing the Pricing VOLL when shortage conditions last exceptionally long.

The System VOLL represents the composite price that consumers are willing to pay to avoid an interruption of electrical service. The System VOLL is used to develop an updated ORDC to appropriately reflect the increased possibility of MISO-directed load curtailment as an Operating Reserve deficiency worsens. The updated values will ensure that MISO's shortage pricing rules maintain and enhance compliance with the Commission's requirement that shortage prices reflect load's willingness to pay to avoid service interruption under shortage conditions.

This proposal is consistent with the recommendations of MISO's Independent Market Monitor ("IMM") to, "Improve shortage pricing by adopting an improved contingency reserve demand curve that reflects the expected value of lost load," as further evidenced by the IMM's affidavit in support of this filing.[3] MISO developed the proposed improvements to its shortage pricing rules and ORDC in the context of its Reliability Imperative framework.[4]

Ultimately, the shortage pricing enhancements proposed herein are just and reasonable as they are consistent with the Commission's policy on price formation and the methodology for establishing VOLL previously accepted by the Commission.[5] As discussed in greater detail below, this proposal has been vetted in MISO's stakeholder process and is a necessary component of MISO's ongoing efforts to maintain and enhance reliability in the MISO Region.

II. BACKGROUND AND OVERVIEW OF FILING

The Tariff revisions proposed herein update and improve the Tariff's rules on the VOLL, Operating Reserve Demand Curves, and EDRs. These changes are the product of MISO's internal studies, and discussions with the IMM and MISO stakeholders. The testimony of Todd Ramey, MISO's Senior Vice President for Markets and Digital Strategy, describes MISO's shortage or scarcity pricing framework.[6] The testimony of Zakaria Joundi, MISO's Executive Director for Market and Grid Strategy, explains the development, methodology and supporting data of MISO's shortage pricing proposal in this filing. The affidavit of Dr. David B. Patton, MISO's IMM,

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[3] 2016 State of the Market Report, Recommendation 2016-1, at xviii, 77-78.

[4] MISO's Reliability Imperative dashboard is available at:
https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/

[5] *Midwest Indep. Trans. Sys. Operator, Inc.*, 122 FERC ¶ 61,172 (2008). *See also, Staff Formation in Wholesale Electricity Markets; Staff Analysis of Shortage Pricing in RTO and ISO Markets*, October 2014, at 2 and n.3, *Price Formation in Organized Wholesale Electricity Markets*, FERC Docket No. AD14-14-000; *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 at P 208 (2008), 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g*, Order No. 719-A, 74 FR 37776 (July 29, 2009), FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[6] Although the terms "shortage" and "scarcity" are often used interchangeably in relation to market pricing, and have been so used in MISO's stakeholder discussions and related documentation, this filing will largely refer to shortage pricing. This more specifically indicates that the proposed pricing rules will apply when supply is short of energy or reserve requirements in varying degrees. More generally, shortage or scarcity pricing refers to the pricing rules that apply "when an RTO or ISO experiences (or nears) a deficiency in one of the ancillary service products or involuntarily curtails load," and the terms "are often, though not always, used synonymously to refer to these pricing events." *Staff Formation in Wholesale Electricity Markets; Staff Analysis of Shortage Pricing in RTO and ISO Markets*, October 2014, at 2 and n.3, *Price Formation in Organized Wholesale Electricity Markets*, FERC Docket No. AD14-14-000.

discusses his recommendations to update the VOLL and Operating Reserve Demand Curves, and the responsiveness of MISO's proposal to his recommendations.

A. FERC Filings and Orders

1. Original VOLL and Operating Reserve Demand Curve Filings and Orders

On February 15, 2007, MISO filed in Docket No. ER07-550-000, proposed Tariff provisions that included the VOLL and Operating Reserve Demand Curves, as part of the establishment of MISO's Energy and Ancillary Services Markets ("ASM"). On June 22, 2007, the Commission issued an order that rejected the original proposal for reasons largely unrelated to VOLL and Demand Curves (*i.e.*, mainly due to the need for a market power analysis, and market readiness and reversion plans), without prejudice to refiling after adopting modifications, and having further market design consultations with stakeholders, in accordance with guidelines provided by the Commission.[7]

On September 14, 2007, as amended on September 19, 2007, MISO filed a revised ASM proposal in Docket Nos. ER07-1372-000 and ER07-1372-001 (collectively, "ASM Filing"), based on the requirements of the Guidance Order. On February 28, 2008, the Commission conditionally accepted the ASM proposal, subject to certain changes,[8] which ensued in several compliance filings and acceptance orders.

a. Shortage Pricing, the VOLL, and Operating Reserve Demand Curves

The Guidance Order stated that, through the VOLL, "scarcity pricing allows the market price to reflect an estimated value of curtailed demand."[9] Linking the VOLL to Operating Reserves, the Commission also described the VOLL as "allowing the market price to rise to levels reflective of a shortage of operating reserves (and hence an increased probability of demand curtailment)."[10] Recognizing that "an appropriate scarcity price is not an exercise in precision," and "represents an estimate of the value of scarcity that is subject to interpretation," the Commission encouraged continued stakeholder discussion to build support for the VOLL that MISO planned to propose.[11]

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[7] *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311 (2007) ("Guidance Order").

[8] *Midwest Indep. Trans. Sys. Operator, Inc.*, 122 FERC ¶ 61,172 (2008) ("ASM Order").

[9] Guidance Order at P 61.

[10] *Id*.

[11] *Id*. at P 63.

The same day the Guidance Order was issued, the Commission also issued an Advanced Notice of Proposed Rulemaking ("ANOPR") regarding shortage pricing.[12] The ANOPR described the following benefits of using shortage pricing under shortage conditions: "a significant incentive for short-term reliability"; "triggering of demand response in shortages"; "incentives for load to contract forward at prices lower than the scarcity prices … to limit its exposure to the scarcity prices"; and "another price signal to the market indicating the value of scarcity reserves."[13] The ANOPR described four ways that shortage pricing can appropriately reflect operating reserve shortage under emergency conditions: (i) increase energy bid and price caps only during an emergency; (ii) raise bid caps only for demand bids, while maintaining generation bid caps; (iii) require a demand curve for operating reserves, such that when available generating capacity falls short of combined energy demand and operating reserve requirements, the market price for energy and operating reserves would increase to specified levels that rise with the severity of the shortage; and (iv) set the market-clearing price at the payment made to participants in an emergency demand response program.[14]

The ASM Order echoed these shortage pricing principles, as did the Notice of Proposed Rulemaking issued on February 22, 2008, regarding shortage pricing.[15] In the ASM Order, the Commission reiterated the Guidance Order's finding that:

> … the demand curves for operating reserves, with corresponding scarcity prices, proposed in the Midwest ISO's filing should provide a significant incentive for short-term reliability, for the triggering of demand response during shortages, and for load to contract forward at prices lower than the scarcity prices. This would reflect the value of reserves and energy during these conditions.[16]

The ASM Order also pointed out that the Competition NOPR required Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") to adopt "reforms to ensure that the market price for energy accurately reflects the value of such energy during periods of scarcity," through one of four methods,[17] which were already described in the Competition ANPRM.[18] On October 17, 2008, Order No. 719 echoed these four methods in the

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[12] *Wholesale Competition in Regions with Organized Electric Markets*, Advance Notice of Proposed Rulemaking, 119 FERC ¶ 61,306 (2007) ("Competition ANPRM").

[13] *Id.*

[14] *Id.* at PP 75-81.

[15] *Wholesale Competition in Regions with Organized Electric Markets*, Notice of Proposed Rulemaking, 122 FERC ¶ 61,167 (2008) ("Competition NOPR").

[16] ASM Order at P 212.

[17] *Id.* at P 213.

[18] Competition NOPR at P 98.

context of requiring RTOs and ISOs to revise their tariffs to ensure that market prices accurately reflect the value of energy during operating reserve shortages.[19]

One such shortage pricing method is the use of demand curves for operating reserves, which MISO's ASM Filing proposed.[20] As explained in the ASM Filing:

> … the Midwest ISO has designed its Energy and Ancillary Services Markets to establish the following product priority from highest to lowest: Energy, Regulating Reserve, Spinning Reserve, and Supplemental Reserve. As a result, use of the Demand Curves in combination with the simultaneous co-optimization process will establish the market value of both Energy and Operating Reserves and the relative value of these products to each other, including during shortage conditions.[21]

In his affidavit in support of the ASM Filing, the IMM described the demand curves as benchmarked to the VOLL, which is "the estimated cost to consumers of electricity of involuntarily losing their supply of electricity."[22] The demand curves establish the shortage prices when cleared reserves are inadequate, in varying degrees, to meet Operating Reserve requirements.[23]

On April 28, 2009, MISO filed in Docket No. ER09-1049-000 proposed Tariff revisions to comply with Order No. 719. On December 15, 2011, the Commission issued an order reiterating that one of the four ways to comply with Order No. 719's price formation requirements is to "establish a demand curve for operating reserves, which has the effect of raising prices in a

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[19] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 at P 208 (2008), 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g*, Order No. 719-A, 74 FR 37776 (July 29, 2009), FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009). Pursuant to Order No. 719, 18 CFR Part 35, § 35.28(g)(iv) ("Price formation during periods of operating reserve shortage") requires as follows:

> Each Commission-approved independent system operator or regional transmission organization must modify its market rules to allow the market-clearing price during periods of operating reserve shortage to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power.

[20] ASM Order at PP 213-14.

[21] ASM Filing at 30.

[22] Affidavit of David B. Patton at P 20, Attachment A to ASM Filing ("Patton Testimony").

[23] *See also* the detailed discussion of the economic principles underlying the demand curves in the Testimony of Michael D. Cadwallader in support of the ASM Filing at 20-30, Attachment H ("Cadwallader Testimony").

previously agreed-upon way as operating reserves grow short."[24] However, the Commission directed MISO to submit a compliance filing demonstrating that the Tariff's use of demand curves met six criteria set forth in Order 719 for assessing the adequacy of shortage pricing rules.[25]

On March 14, 2012, as amended on March 23, 2012, MISO submitted in Docket No. ER12-1265-000, *et al.*, a filing to comply with the December 15, 2011, order regarding Order No. 719 compliance. On July 19, 2012, the Commission accepted MISO's compliance filing as providing an adequate factual record regarding consistency of MISO's demand curves with Order No. 719's six criteria.[26] The Commission agreed that MISO's shortage pricing rules:

(i) Improve reliability during periods of operating reserve shortages because, as operating reserves are depleted, MISO progressively raises energy and operating reserve prices within reserve zones, thereby increasing supply and reducing demand to improve reliability.

(ii) Make it worthwhile for customers to invest in demand response technologies because elevated prices increase customers' costs for consuming energy.

(iii) Encourage existing generation and demand resources to remain in business because high prices during shortage conditions create incentives for demand reductions and supply resource availability when and where needed most.

(iv) Encourage the entry of new generation and demand resources, as new investment is driven by projections of future market prices and the resultant profits or cost savings; and provide developers with certainty regarding elevated future energy prices during times of supply shortage.

(v) Treat demand response resources comparably to other resources during operating reserve shortages because they are paid the same prices as generation resources.

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[24] *Midwest Indep. Transmission Sys. Operator, Inc.*, 137 FERC ¶ 61,214 at n.288 (2011).

[25] *Id.* at P 231. The six criteria are:

> (1) improve reliability by reducing demand and increasing supply during periods of operating reserve shortages; (2) make it more worthwhile for customers to invest in demand response technologies; (3) encourage existing generation and demand resources to continue to be relied upon during an operating reserve shortage; (4) encourage entry of new generation and demand resources; (5) ensure that the principle of comparability in treatment of and compensation to all resources is not discarded during periods of operating reserve shortage; and (6) ensure market power is mitigated and gaming behavior is deterred during periods of operating reserve shortages including, but not limited to, showing how demand resources discipline bidding behavior to competitive levels. Order No. 719 at PP 246-247.

[26] *Midwest Indep. Trans. Sys. Operator, Inc.*, 140 FERC ¶ 61,060 (2012).

(vi) Include appropriate market power mitigation provisions during operating reserve shortages, as MISO works closely with the IMM to evaluate whether market participants are attempting to exercise market power or engage in gaming behaviors, and continually attempts to improve its market rules and procedures.[27]

b. Methodology and Supporting Data for Existing VOLL

The Tariff currently defines the VOLL as follows:

> The maximum value associated with the Operating Reserve Demand Curve that represents the average cost to consumers of an interruption of firm demand as specified in Schedule 28.

Schedule 28 (titled "Demand Curves for Operating Reserve, Regulating and Spinning Reserve, and Regulating Reserve, Up Ramp Capability, Down Ramp Capability, and Market-Wide Short-Term Reserve") of the Tariff specifies in section III.iv that the VOLL is $3,500/MWh.

The ASM Order found acceptable the methodology and supporting data that MISO used to determine the existing VOLL of $3,500/MWh. According to the Commission:

> We recognize that ***estimating*** **the** ***VOLL***, associated with involuntary load curtailments, ***is not an exact science*****.** ***The Midwest ISO's data*** **and** ***assumptions, however, are reasonable***. The Midwest ISO ***uses statistical data from eight different LSEs over a 14-year period providing a fairly large sample and outage costs with different durations and frequencies. This is a reasonable proxy to calculate the VOLL***. (Emphasis added.)[28]

As further explained in the testimony of Mr. Roy Jones, MISO's then Executive Director of the Ancillary Services Markets Project,[29] the existing VOLL represents, "the average maximum price a consumer is willing to pay to avoid firm load interruption under Capacity shortages," with a "focus on consumers or consumer classes most likely to sustain a firm load interruption as a result of a Capacity shortage."[30] According to Mr. Jones, the VOLL was estimated based on a statistical approach that used a meta-analysis of 24 studies involving eight Load Serving Entities ("LSEs") from 1989 to 2002, covering more than a decade. For purposes of comparability, the estimates were converted to 2005 dollars. Because it was difficult to directly estimate the value to customers of reliable uninterrupted service, MISO used as a proxy estimates of outage costs that varied by market segment, temporal factors, duration, frequency, and how much advance notice

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[27] *Id*. at PP 153-154.

[28] ASM Order at P 215.

[29] Testimony of Roy Jones at p. 103 (Attachment E to ASM Filing) ("Jones Testimony").

[30] *Id*.

customers had. The data included "direct surveys, revealed preference approaches and consumer surplus estimation methods."[31]

Median values and distributions were calculated for residential, commercial, and industrial customers. The values for commercial and industrial customers were calculated by market segment, broadly using 2-digit Standard Industrial Classification ("SIC") categories. To arrive at the $3,500/MWh VOLL, MISO estimated an average of the median values for the residential class, and the lowest median value of the small commercial and industrial classes. The VOLL represented an estimate for the market segment that least values uninterrupted electrical service, by calculating the average based on weights of "0.85 for residential and 0.15 for small commercial and industrial services."[32]

The Jones testimony summarized the data used to calculate VOLL as follows:

> For the Midwest ISO footprint, once the specification was estimated, and tested for reasonableness of the estimated coefficients and statistical significance of each, Midwest specific data was used for the independent variables. To obtain distributions for estimates of 5 residential outage costs, household level data from the Department of Labor's Consumer Expenditure Survey ("CES") was utilized. To obtain distributions for estimates of commercial and industrial outage costs, the following sources of data were used: (1) the Commercial Buildings Energy Consumption Survey ("CBECS"); (2) the Manufacturing Energy Consumption Survey ("MECS"); (3) the Economic Census; and (4) the Agriculture Resource Management Survey; as well as other sources of data specific to the Midwest.[33]

c. Original Demand Curves Accepted by ASM Order

i. Original Market-Wide Operating Reserve Demand Curve

As accepted by the ASM Order, the Market-Wide Operating Reserve Demand Curve under Schedule 28 of the Tariff was originally structured as follows:

- When the cleared Operating Reserve was less than the Market-Wide Operating Reserve Requirement, the Demand Curve price was the product of:

The VOLL; and

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[31] *Id.*

[32] *Id.* at p. 104.

[33] *Id.*

> The estimated conditional probability of a loss of load if a single forced Resource outage of 100 MW or more will occur at the cleared Market-Wide Operating Reserve level for which the price is determined.

- The minimum Scarcity Price was $1,100/MWh, consisting of the sum of:

  Energy Offer Price Cap ($1,000/MWh); and

  Contingency Reserve Offer Price Cap ($100/MWh)

- The maximum Scarcity Price was the VOLL less the maximum Market-Wide Regulating Reserve Demand Curve level for the month.

ii. Original Reserve Zone Operating Reserve Demand Curve

On the other hand, the Reserve Zone Operating Reserve Demand Curve was structured as follows:

- When the cleared Operating Reserve was equal to or more than ten percent (10%) of the requirement level: The sum of the Energy Offer Price Cap and the Contingency Reserve Offer Price Cap.

- When the cleared Operating Reserve was less than ten percent (10%) of the requirement level: The VOLL less the maximum Regulating Reserve Demand Curve Scarcity Price for the Reserve Zone.

The provisions of Schedule 28 regarding Reserve Zone Operating Reserve Demand Curves were removed by subsequent Tariff provisions, filed on March 30, 2018 and accepted on April 27, 2018 in Docket No. ER18-1262-000, that considered Post Reserve Deployment Constraints in the zonal reserve procurement process, in lieu of using minimum zonal reserve requirements established by offline Reserve Zone Requirements Studies.[34] Accordingly, this filing will not discuss the previous zonal Operating Reserve Demand Curves.

iii. Methodology and Supporting Data for Original Market-Wide Operating Reserve Demand Curve

The ASM Filing proposed the adoption of shortage pricing in the Day-Ahead Market and the Real-Time Market by using a demand curve for Operating Reserves, with co-optimization of Energy and Ancillary Service prices.[35] Shortage pricing would use clearing prices established by the demand curves when available Capacity is insufficient to meet Operating Reserve requirements in an hour or five-minute Dispatch Interval. The minimum Operating Reserve shortage price was

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[34] *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER18-1262-000 (Apr. 27, 2018) (delegated letter order).

[35] ASM Order at P 191.

to be $1,100/MWh, representing the sum of the then Energy offer cap of $1,000/MWh (now known as the Energy Offer Soft Price Cap) and the Operating Reserve offer cap of $100/MWh. The maximum Operating Reserve shortage price was to be $2,500/MWh, based on the existing VOLL of $3,500/MWh, less the then $1,000/MWh minimum Regulating Reserve scarcity price.[36]

The Market-Wide Operating Reserve Curves were constructed based on the following reserve pricing principles:

- VOLL vis-à-vis Load Shedding events: Because an Operating Reserve deficiency increases the risk of not having enough Capacity to supply firm Energy, the establishment of the Market-Wide Operating Reserve Demand Curve needs to account for both the VOLL, and the probability of an event that reduces Capacity to a level that necessitates Load Shedding.[37]

- Generation outages vis-à-vis Load Shedding: Because the forced outage of a Generation Resource is the most common event that could cause a loss of Load due to deficient Operating Reserves, the Market-Wide Operating Reserve Demand Curve was approximated by setting the Demand Curve price for a specific Operating Reserve level as the product of the VOLL and the conditional probability that a loss of Load will occur if there is an outage of a single Generation Resource with a Capacity of at least 100 MW, the threshold reserve level below which Load Shedding could be directed.[38]

- Price when reserves are sufficient or deficient: The Demand Curve price would be zero dollars per MWh if the cleared reserve level equals or exceeds Market-Wide Operating Reserve Requirements, or the largest Generation Resource's Capacity (*i.e.*, if there is no reserve deficiency); and it would be the product of VOLL and the estimated conditional probability of loss of load given that a single forced Resource outage of 100 MW or greater will occur at the cleared Market-Wide Operating Reserve level.[39]

- Maximum demand curve shortage price not to exceed VOLL: To ensure that LMPs and MCPs do not exceed VOLL where there is no Load Shedding, there should be a maximum shortage price for Market-Wide Operating Reserve Demand Curve that is less than the VOLL.[40]

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[36] *Id*.

[37] Jones Testimony at p. 97.

[38] *Id*. at pp. 97-98.

[39] *Id*.

[40] *Id.* at pp. 98-100.

- Minimum demand curve shortage price: The minimum shortage price of the Market-Wide Operating Reserve Demand Curve was based on an estimate of the highest supply cost of a Generation Resource to supply Operating Reserve, with such cost consisting of the highest potential Operating Reserve Offer and the highest potential Opportunity Cost incurred by a Generation Resource to supply Operating Reserve.[41] The highest potential Operating Reserve Offer was established as $100/MWh, which is the Contingency Reserve Offer Price Cap, because most of the Market-Wide Operating Reserve Requirement consists of Contingency Reserve, which is prioritized below Regulating Reserve.[42] Ignoring differences in loss sensitivities, the maximum loss of incremental Energy margins as a result of supplying an incremental amount of Operating Reserve is $1,000/MWh, the Offer Price Cap for Energy then.[43]

2. Original EDR Filing and Order

The Guidance Order also required MISO to address the market participation of demand response under emergency conditions.[44] Accordingly, on December 31, 2007, MISO filed Tariff provisions regarding EDRs in Docket No. ER08-404-000. Subsequently, the ASM Order stated that MISO's EDR proposal would be resolved in the docket where it was filed.[45] On April 22, 2008, the Commission accepted the Tariff's EDR provisions.[46]

The Tariff defines EDRs as follows:

> The commitment and dispatch of Load reductions, Behind the Meter Generation Resources and other Demand Resources during an Emergency, in accordance with Schedule 30.

In his most recent quarterly report to the MISO Board of Directors, MISO's IMM, Dr. David Patton, made a recommendation to "Eliminate EDR resources as a class of demand response."[47] This recommendation was based on the IMM's evaluation of demand response in MISO in which the IMM found that 48% of Load Modifying Resources ("LMR") are dual registered as EDR. The IMM notes that EDRs are called very late in MISO's emergency

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[41] *Id*. at pp. 99-100.

[42] *Id*. at p. 99.

[43] *Id*. at p. 100.

[44] Guidance Order at P 70.

[45] *Id*. at P 328.

[46] *Midwest Indep. Trans. Sys. Operator, Inc.*, 123 FERC ¶ 61,070 (2008).

[47] *IMM Quarterly Report: Summer 2024*, Potomac Economics, at slide 11, https://cdn.misoenergy.org/20240917%20Markets%20Committee%20of%20the%20BOD%20Item%2006%20IMM%20Quarterly%20Report647070.pdf, September 17, 2024.

procedures, which in effect enables EDRs to receive capacity payments with virtually no chance of having to perform.[48]

Based upon the IMM's recent recommendation, MISO is evaluating the long-term viability of EDRs. Any further changes to the Tariff impacting EDRs will be submitted to the Commission in a future Section 205 FPA filing. It is important to note that, because EDRs are rarely used, and as such do not significantly impact pricing, their future elimination will not negatively impact shortage pricing.

3. Operating Reserve Demand Curve Changes

a. Scaling Based on Operating Reserve Cleared vis-à-vis Operating Reserve Requirement, and Accounting for Minor Momentary Shortages

On February 11, 2013, MISO filed in Docket No. ER13-921-000 revisions to Schedule 28 so that the Market-Wide Operating Reserve Demand Curve would not be based on a static MW value, but instead would be defined as a percentage of the Market-Wide Operating Reserve Requirement. In addition, the Market-Wide Operating Reserve Demand Curve (as well as the then Reserve Zone Operating Reserve Demand Curve) was modified to moderately price Economic Shortages (*i.e.*, small and momentary shortages lasting only two 5-minute Dispatch Intervals), as distinguished from Reliability Shortages. On April 23, 2013, the Commission accepted the Schedule 28 changes.[49]

The Market-Wide Operating Reserve Demand Curve price was determined in accordance with three percentage range segments:

- If less than four percent (4%) of the requirement level cleared: The VOLL less the Market-Wide Regulating Reserve Demand Curve price for the month.

- If more than four percent (4%) but less than ninety-six (96%) of the requirement level cleared:

  The Scarcity Price was the product of the VOLL and the estimated conditional probability of a loss of load based on the occurrence of a forced Resource outage of 100 MW or more at the cleared Market-Wide Operating Reserve level;

  The maximum price was the VOLL less the maximum Market-Wide Regulating Reserve Demand Curve for the month; and

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[48] *See Id.* at slide 10.

[49] *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER13-921-000 (April 23, 2013) (delegated letter order).

The minimum price was the sum of the Energy Offer Price Cap and the Contingency Reserve Offer Price Cap.

- If more than ninety-six (96%) but less than one hundred percent (100%) of the requirement level cleared: $200/MWh.

b. Order No. 831 Conforming Changes

On November 13, 2018, MISO filed in Docket No. ER19-328-000, as amended on December 18, 2018, Tariff revisions to conform Schedule 28 to the offer and price cap requirements of Order No. 831.[50] Although not required by Order No. 831, the Tariff revisions also adopted the Energy Offer Hard Price Cap of $2,000 as a cap on Day-Ahead Price-Sensitive Bids and Virtual Demand Bids. On January 10, 2019, the Commission accepted the Schedule 28 changes.[51]

Under Order No. 831, RTOs and ISOs were required to implement an energy offer cap structure: (1) with a "soft" cap on each resource's incremental energy offer at the higher of $1,000/MWh, or that resource's verified cost-based incremental energy offer; and (2) with a "hard" cap on verified cost-based incremental energy offers at $2,000/MWh for purposes of calculating locational marginal prices ("LMP"), while allowing recovery of verified costs above such amount.

Accordingly, MISO aligned Schedule 28 with MISO's earlier Tariff revisions in compliance with Order No. 831.[52] First, the Market-Wide Operating Reserve Demand Curve, which then used a $1,000/MWh Energy Offer Price Cap, was modified to instead use the Energy Offer Hard Price Cap. Second, MISO added the Most Severe Single Contingency as a threshold, so that reserve shortages could be priced up to the Energy Offer Hard Price Cap plus the Contingency Reserve Offer Price Cap when cleared reserves drop below that level, and up to the Energy Offer Soft Price Cap plus the Contingency Reserve Offer Price Cap when cleared reserves are above that level.

In particular, the reserve pricing structure was as follows:

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[50] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 81 FR 87770 (Dec. 15, 2016), Order No. 831, 157 FERC ¶ 61,115 (2016), *order on reh'g and clarification*, Order No. 831-A, 82 Fed. Reg. 53,403 (Nov. 16, 2017), FERC Stats. & Regs. ¶ 31,394 (2017).

[51] *Midwest Indep. Transmission Sys. Operator, Inc*., Docket No. ER19-328-001 (January 10, 2019) (delegated letter order).

[52] *Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,270 (2018); *Midcontinent Indep. Sys. Operator, Inc.* 165 FERC ¶ 61,004 (2018); Joundi Testimony at pp. 8-9.

- If less than four percent (4%) of the requirement level cleared: The VOLL less the Market-Wide Regulating Reserve Demand Curve price for the month.

- If more than four percent (4%) but less than ninety-six (96%) of the requirement level cleared:

  If the cleared amount was not sufficient to satisfy the Most Severe Single Contingency, the minimum price was the sum of the Energy Offer Hard Price Cap and the Contingency Reserve Offer Hard Price Cap.

  If the cleared amount was sufficient to satisfy the Most Severe Single Contingency, the minimum price was the sum of the Energy Offer Soft Price Cap and the Contingency Reserve Offer Hard Price Cap.

- If more than ninety-six (96%) but less than one hundred percent (100%) of the requirement level cleared: $200/MWh.

c. Alignment with Emergency Pricing Construct, and Ramp Capability Product

On August 31, 2021, MISO filed in Docket No. ER21-2797-000 Tariff revisions to align Schedule 28 with MISO's then newly revised emergency pricing construct,[53] and successful implementation of the Ramp Capability Product.[54] On December 6, 2021, the Commission accepted the Schedule 28 changes.[55]

The revisions removed the last step ($200/MWh) in Schedule 28's pricing of Market-Wide Operating Reserve because that price was an inadequate incentive, and inhibited the procurement of available reserves above such price; and the Ramp Capability Product largely addresses 5-10 minute shortages by holding ramp capability in reserve to manage 10-minute net load variations.

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[53] *Midcontinent Indep. Sys. Operator, Inc.*, 175 FERC ¶ 61,093 (2021).

[54] *Midcontinent Indep. Sys. Operator, Inc.*, 149 FERC ¶ 61,095 (2014); *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER14-2156-001 (Sept. 16, 2015) (delegated letter order); *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER16-815-001 (April 8, 2016) (delegated letter order).

[55] *Midcontinent Indep. Sys. Operator, Inc.*, 177 FERC ¶ 61,171 (2021).

As a result, the last reserve pricing step is $1,100/MWh, representing the Energy Offer Soft Price Cap plus the Contingency Reserve Offer Hard Price Cap. The Commission found this consistent with the second tier of MISO's emergency pricing construct.[56]

As thus revised, the current reserve pricing structure is as follows:

- If less than four percent (4%) of the requirement level cleared: the VOLL less the Market-Wide Regulating Reserve Demand Curve price for the month.

- If more than four percent (4%) of the requirement level cleared:

> If the cleared amount was not sufficient to satisfy the Most Severe Single Contingency, the minimum price was the sum of the Energy Offer Hard Price Cap and the Contingency Reserve Offer Hard Price Cap.
>
> If the cleared amount was sufficient to satisfy the Most Severe Single Contingency, the minimum price was the sum of the Energy Offer Soft Price Cap and the Contingency Reserve Offer Hard Price Cap.

d. Current Definition of Operating Reserve Demand Curves

The Tariff currently defines Market-Wide Operating Reserve Demand Curves as follows:

> A series of quantity/price points as defined in Schedule 28 that is used to calculate the Shadow Price of a particular Operating Reserve[57] requirement constraint when there is a shortage of Operating Reserve cleared on a Transmission Provider Region-wide basis.[58]

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56 MISO's emergency pricing framework uses two offer floors under Schedule 29A of the Tariff: an Emergency Tier I Offer Floor, which is the maximum of $500/MWh or the highest available economic offer up to the Energy Offer Hard Price Cap; and an Emergency Tier II Offer Floor, which is the maximum of $1,000/MWh or the highest available economic or emergency offers up to the Energy Offer Hard Price Cap.

57 The Tariff defines Operating Reserve as follows:

> That capability above firm system demand maintained to provide for Regulation, Load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of Regulating Reserve, Contingency Reserve, Up Ramp Capability and Down Ramp Capability.

58 Demand Curves are defined by the Tariff as follows:

> The Market Wide Regulating Reserve Demand Curve, the Market Wide Regulating and Spinning Reserve Demand Curve, *the Market Wide Operating Reserve Demand Curve*, the Market Wide Up Ramp Capability Demand Curve, the Market Wide Down Ramp

4. Four Current Functions of Existing VOLL

The existing VOLL currently serves four pricing functions. First, the VOLL is a price cap on LMPs and MCPs both in the Day-Ahead Market[59] and the Real-Time Market.[60] Second, the VOLL serves as an administrative price during EEA-Level 3 Capacity Emergencies that involve MISO-directed Load Shedding.[61] Third, VOLL is at the top of the Market-Wide Operating Reserve Demand Curve.[62] Fourth, the VOLL is a cap on EDR Offers.[63]

5. Market Monitoring, Mitigation and Reporting of Physical Withholding

To prevent or address potential exercises of market power during shortage conditions, the Guidance Order urged MISO to make it mandatory under the Tariff that physical withholding under such conditions be monitored and audited, and any actual instances be mitigated and reported, by MISO's IMM.[64]

Accordingly, MISO proposed, and the Commission accepted as sufficient, section 53.1A of Module D of the Tariff, which provides for the required monitoring, auditing and reporting, in conjunction with the provisions of section 64.1.1, on the mitigation of any physical withholding that may occur during periods of shortage.[65]

B. Impetus, Need and Framework for Updating Rules on the VOLL, Operating Reserve Demand Curves, and EDR Offer Cap

In the ASM Filing, MISO committed to work with stakeholders on developing a methodology for calculating and establishing the appropriate periodicity for updating the calculation of the VOLL.[66] The ASM Order directed MISO to describe the methodology when revising the Tariff to update the VOLL, as the Commission will, "review whether the values used in the demand curve remain just and reasonable."[67]

Capability Demand Curve, and/or the Market Wide Short-Term Reserve Demand Curve. (Emphasis added.)

59 Section 39.2.9.p of the Tariff.

60 Section 40.2.15.p of the Tariff.

61 Section 40.2.20.b.iii of the Tariff.

62 Section III of Schedule 28 of the Tariff.

63 Section IV of Schedule 30 of the Tariff.

64 Guidance Order at P 61.

65 ASM Order at PP 151-155, 212-214.

66 *Id.* at n.67; Jones Testimony at p. 105.

67 ASM Order at P 216.

MISO's consideration of potential improvements to the Tariff's price formulation rules later ensued in further discussions with the IMM, and with MISO's stakeholders, regarding the methodology and approach for updating the VOLL and the Operating Reserve Demand Curves.

1. IMM's State of the Market Report Recommendations

In the 2016 State of the Market Report, the IMM made his Recommendation 2016-1, entitled: "Improve shortage pricing by adopting an improved contingency reserve demand curve that reflects the expected value of lost load."[68] The IMM explained that the Operating Reserve Demand Curve does not adequately reflect reliability value because it overstates the reliability risks for small shortages and understates those risks for deep shortages. The IMM also noted the possibility of inefficient imports and exports when markets are tight in both MISO and PJM because the latter's rules price modest shortages as high as $6,000/MWh.[69]

According to the IMM, an ideal Operating Reserve Demand Curve should reflect the expected VOLL, which is equal to the probability of losing load multiplied by the net VOLL.[70] The IMM viewed MISO's existing VOLL as too low, and recommended that MISO update its VOLL and determine the slope of the Operating Reserve Demand Curve based on how capacity levels affect the loss of load probability, as that approach would track how increasing shortfalls escalate the risk of losing load. The IMM performed a detailed analysis in support of a more efficient Operating Reserve Demand Curve.[71] The IMM subsequently recommended that the VOLL be raised to more than $20,000, [72] which he later increased to $30,000;[73] and that the Operating Reserve Demand Curve be capped at $10,000/MWh for deep shortages.[74] The IMM noted that MISO planned to evaluate the IMM's methodology for creating a loss-of-load probability curve for different reserve levels, or develop an alternative methodology.[75]

2. MISO's Roadmap, MSC Issue Statement, and the Reliability Imperative

As explained by Todd Ramey, MISO's Senior Vice President for Markets and Digital Strategy, MISO responded to the IMM's recommendations to update the VOLL and the Operating

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[68] 2016 State of the Market Report, Recommendation 2016-1, at xviii, 77-78.

[69] *Id.* at 77.

[70] *Id*.

[71] 2018 State of the Market Report at 99.

[72] 2019 State of the Market Report at 118.

[73] 2023 State of the Market Report at 101.

[74] 2019 State of the Market Report at 118.

[75] *Id*. The IMM's 2022 State of the Market Report subsequently also made recommendation 2022-1, to update the Transmission Constraint Demand Curve. MISO agrees in principle with the need to consider an update, but plans to pursue that matter starting next year.

Reserve Demand Curve by including shortage pricing improvements in MISO's market design plans (previously called Market Roadmap, and renamed as the Integrated Roadmap).[76] The consideration of shortage pricing improvements was designated initially as IR060,[77] and was replaced by IR071.[78] Then shortage pricing improvements were framed as an issue statement to be addressed in consultation with the Market Subcommittee ("MSC 2019-1").[79] Stakeholder discussions commenced in 2020.

As further discussed by Mr. Ramey, the improvement of shortage pricing was also included in MISO's Reliability Imperative framework.[80] The Reliability Imperative denotes and integrates the range of efforts MISO is pursuing, in consultation with its member utilities, and the state regulators within its footprint, to explore and make timely system and operational adjustments needed to ensure the system remains reliable as the region's resource mix changes.[81] One of the four "Pillars" of the Reliability Imperative is Market Redefinition,[82] which seeks to:

> ***Enhance and optimize MISO's markets to ensure continued reliability and efficiency*** while enabling the changing resource mix, responding to more frequent extreme weather events, and preparing for increasing electrification
>
> - Ensure ***accurate pricing*** of energy & reserves (Emphasis added.)[83]

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[76] Testimony of Todd Ramey at p. 5 ("Ramey Testimony").

[77] IR060 – Improved Contingency Reserve Demand Curve that reflects VOLL, available at:

https://www.misoenergy.org/engage/MISO-Dashboard/improved-contingency-reserve-demand-curve-that-reflects-voll/

[78] IRO071 – Continued Reforms to Improve Scarcity Pricing and Price Formation.

[79] MSC 2019-1 – Continued Reforms to Improve Scarcity Pricing and Price Formation (fka IR071), available at:

https://www.misoenergy.org/engage/MISO-Dashboard/continued-reforms-to-improve-scarcity-pricing-and-price-formation/

[80] Ramey Testimony at p. 5. MISO's Reliability Imperative dashboard is available at:

https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/

[81] Ramey Testimony at p. 6.

[82] *Id*. at p. 7.

[83] The Four Pillars of the Reliability Imperative are Market Redefinition, Operations of the Future, Transmission Evolution and System Enhancements. *See* Ramey Testimony at p. 7. They are summarized at:

https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/

As also noted by Mr. Ramey,[84] MISO's shortage pricing studies resulted in the development of an Emergency Pricing Evaluation in September 2020;[85] a Scarcity Pricing Evaluation in March 2021;[86] a Scarcity Pricing White Paper in March 2024, and most recently, an updated Shortage Pricing White Paper in November 2024.[87]

The principles, goals, objectives and other considerations that guided MISO's shortage pricing studies are described below.

3. The Commission's Price Formation Goals

Mr. Ramey points out that MISO's shortage pricing studies have been guided by the following price formation goals articulated by the Commission in Docket No. AD14-14-000:[88]

- Maximize market surplus for consumers and suppliers;
- Provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability;

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84 Ramey Testimony at p. 5.

85 The Emergency Pricing Evaluation (September 2020) is available at:

https://cdn.misoenergy.org/RAN%20Emergency%20Pricing%20Evaluation%20Paper%20Sept%202020475337.pdf

86 The Scarcity Pricing Evaluation (March 2021) is available at:

https://cdn.misoenergy.org/20210513%20MSC%20Item%20XX%20Scarcity%20Pricing%20Evaluation%20Paper550162.pdf

The Tariff change filed on August 31, 2021, to remove the $200/MWh step from the Operating Reserve Demand Curve (summarized *supra*) was based on the recommendation of the Scarcity Pricing Evaluation at 16.

87 The Scarcity Pricing White Paper (March 2024) is available at:

https://cdn.misoenergy.org/20240418%20MSC%20Item%2004d%20Scarcity%20Pricing%20White%20Paper%20VOLL%20and%20ORDC632355.pdf

MISO has updated the White Paper to include a discussion of the proposed circuit breaker mechanism. This paper is referred to as the "Shortage Pricing White Paper." The updated Shortage Pricing White Paper link is available at:

https://cdn.misoenergy.org/MISO%20Updated%20Shortage%20Pricing%20White%20Paper%20-%20Nov%202024663437.pdf

88 Ramey Testimony at p. 4.

- Provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and,

- Ensure that all suppliers have an opportunity to recover their costs.[89]

4. MISO's Market Design Guiding Principles

Mr. Ramey participated as a MISO representative in the technical conference and workshops held in Docket No. AD14-14-000. As a workshop panelist, Mr. Ramey stated that the main goal of shortage pricing in MISO is to appropriately reflect any tight system conditions and the marginal cost of the Resources used and steps taken to maintain reliability.[90]

MISO has used the following principles to guide its market design:

- Support an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity;

- Facilitate non-discriminatory market participation regardless of resource type, business model, sector or location;

- Develop transparent market prices reflective of marginal system cost and cost allocation reflective of cost-causation and service beneficiaries;

- Support market participants in making efficient operational and investment decisions; and,

- Maximize alignment of market requirements with system reliability requirements.

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[89] Notice Inviting Post-Technical Workshop Comments, Docket No. AD14-14-000, *In the matter of: Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operator*s, at 3 (Jan. 16, 2015); Notice, Docket No. AD14-14-000 (June 19, 2014).

[90] *In the matter of: Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators,* Docket No. AD14-14-000, Scarcity and Shortage Pricing, Offer Mitigation, and Other Price Caps Workshop, Panel I: Goals of Scarcity and Shortage Pricing and Performance of Existing Pricing Rules, October 28, 2014, Transcript at 16-19, 40-43, 53-54, 56-57, 61-62, 71-73, 77-79, 80-81, 86-87.

The above principles were derived from the Commission's policy pronouncements in Order No. 888[91] and Order No. 2000,[92] and were formulated starting in 2014 in consultation with stakeholders.[93]

5. MISO's Shortage Pricing Objectives

Mr. Joundi's testimony explains that MISO's shortage pricing studies and ensuing proposal are based on MISO's market designed guiding principles enumerated above.[94] As Mr. Joundi explains, the proposal is expected to produce both short-term and longer-term outcomes that are consistent with MISO's market design guiding principles as summarized below:

- Short-term outcomes of the shortage pricing reforms are expected to provide proper financial incentives, and will improve reliability by encouraging appropriate Market Participant actions. If shortage events occur, financial risks will be directed to Market Participants that deviate from their Day-Ahead Market positions and are inflexible to respond to Real-Time Market prices. These expected outcomes are consistent with the guiding principles of supporting an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity; supporting market participants in making efficient operational and investment decisions; and maximizing alignment of market requirements with system reliability requirements.

- In the longer-term, the shortage pricing proposal is expected to inform investment decisions for reliable, flexible resources, which is consistent with the guiding principle

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91 *See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000) (TAPS v. FERC), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

92 *See Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (February 25, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *petitions for review dismissed*, *Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

93 Ramey Testimony at p. 2. MISO recently requested the MSC for feedback on any potential need to further refine or update the above market design guiding principles. Stakeholder feedback, and MISO's responses, are summarized at:

https://www.misoenergy.org/engage/stakeholder-feedback/2024/msc-market-guiding-principles-20240822/

94 Joundi Testimony at p. 62.

of supporting market participants in making efficient operational and investment decisions.[95]

C. Need to Update VOLL for LMPs and MCPs, and for Administrative Pricing, and Adopt Market Pricing "Circuit Breakers"

1. Need for VOLL Update

Several limitations have been identified with the current shortage pricing mechanism. For example:

- As a price cap, at its current level that has not been updated since 2009, the VOLL: (a) can curtail valid market prices thereby reducing price transparency; and (b) is not sufficiently high to encourage full participation of supply and demand resources and interchange during shortage conditions.
- As an administrative price applied during MISO-directed load-shedding, the non-updated VOLL is below the industry-accepted willingness to pay, particularly according to more recent willingness to pay studies for firm loads. Because of the low cap, prices can be truncated and too low during reserve/transmission shortages.
- The current ORDC does not properly increase for greater Operating Reserve shortage and reduces congestion-management effectiveness for small Operating Reserve shortage. The ORDC is linked to VOLL, and is dominated by two fixed steps ($1,100 and $2,100). The relatively flat shape/magnitude of the current ORDC, as well as its non-updated lower/upper bounds, hampers the ORDC's ability to produce prices that appropriately reflect shortage conditions of varying degrees.[96]

An appropriate VOLL helps to establish efficient economic signals to promote optimal interchange and generator commitments in the short run, efficiently compensates flexible resources, and guides investment and retirement decisions in the long term. Mr. Joundi explains that the current understated VOLL of $3,500/MWh would not send the economic signals needed to produce these positive results.[97] Additionally, an understated VOLL will result in market signals that do not sufficiently guide Market Participants in their longer-term decisions regarding fuel purchases, maintenance planning, power plant upgrades, power-purchase agreements, investment in demand response, and the creation and/or retention of flexible supply resources.[98]

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[95] Joundi Testimony at pp. 62-63.

[96] *Id*. at p. 23.

[97] *Id*. at p. 23.

[98] *Id*. at p. 24.

In summary, increasing the VOLL and adjusting the ORDC will better align shortage pricing with the marginal reliability of diminished reserve margins and curtailments of firm energy needs.

As discussed later in this filing, MISO proposes to rename the VOLL as the "Pricing" VOLL in relation to its function as a price cap on LMPs and MCPs, and as an administrative shortage price during EEA-Level 3 Capacity shortages with MISO-directed Load shedding. MISO's proposed Pricing VOLL has several advantages. First, it provides a more transparent price signal because it is based on, and better accounts for, updated Willingness to Pay data for key load classes, and aligns with MISO's market design principle that prices reflect marginal system costs.[99] Second, it allows market prices to exceed the willingness to pay threshold for many loads, providing a financial incentive to reduce real-time consumption.[100] Third, this Pricing VOLL is a large enough price signal to incent incremental emergency supply from all resource types, as well as interchange with our neighbors, and aligns with MISO's market design principle that prices should enhance the ability of Market Participants to make efficient operational and investment decisions.[101] This level of potential real-time VOLL pricing will also encourage greater participation and hedging in the Day-Ahead Market, particularly when tight operating conditions are anticipated.[102]

Fourth, this Pricing VOLL, combined with an appropriately designed ORDC, provides room for all pricing components, including Marginal Energy Component ("MEC"), Marginal Congestion Component ("MCC") and Marginal Loss Component ("MLC") to function before prices are capped.[103] MEC would effectively be capped (~$8,700 - $9,000/MWh) considering all demand curves and offer caps. Figure 6 ("Illustration of Maximum MEC") in Mr. Joundi's testimony illustrates that the maximum MEC for the proposed ORDC is ~$8,800/MWh, assuming a Regulating Reserve Demand Curve of $200.[104] Fifth, the Pricing VOLL avoids setting prices too high, which would expose Market Participants to greater financial risk during periods of extended VOLL pricing.[105]

During stakeholder discussions, MISO further identified the need to address or reduce the financial risk of unduly maintaining unhedged, very high shortage prices for extended periods. That risk is addressed below in this filing's discussion of "circuit breakers," *i.e.*, a mechanism to adjust the VOLL downward if an EEA-Level 3 Capacity shortage lingers from hours to days.

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[99] *Id*. at p. 34.

[100] *Id*.

[101] *Id*.

[102] *Id*.

[103] *Id*.

[104] *Id*.

[105] *Id*. at p. 35.

2. Need for Circuit Breakers

Although EEA – Level 3 events lasting more than a few hours are unlikely based on experience and planning studies, the proposed increase in the Pricing VOLL prompted some stakeholder and state commission concern about the significant financial risks Market Participants may face in the event that shortage conditions somehow last long and the high prices do not lead to changes in behavior.[106] MISO considers it prudent and reasonable to respond to such stakeholder concerns by establishing mechanisms to mitigate the financial impacts of long-duration shortage conditions, even if they may be rare.[107] Accordingly, MISO developed a Pricing VOLL Circuit Breaker ("CB").[108] A Pricing VOLL CB would limit excessive market risk resulting from high prices over an extended period of shortage pricing.[109]

3. Removal of $2,000/MWh cap for Day-Ahead Price-Sensitive Bids and Virtual Demand Bids

MISO recommends removing the $2,000/MWh cap for Day-Ahead Price-Sensitive Bids and Virtual Demand Bids because MISO considers it unnecessary and inappropriate to apply the Energy Offer Hard Price Cap to such Bids.[110] The cap was applied as part of the momentum in complying with Order No. 831, but was not required by Order No. 831.[111] Before Order No. 831, there were no day-ahead bid caps in the MISO Tariff.[112] The application of this bid cap prevents Day-Ahead Price Sensitive Demand from specifying a value between $2,000/MWh and VOLL.[113] In contrast, Fixed Demand Bids will clear at any price, up to the existing VOLL.[114] There is no viable policy reason not to allow Day-Ahead Price Sensitive Demand to likewise bid beyond the $2,000/MWh price cap.[115]

The present filing's proposal to increase the VOLL is an opportune time to remove the Energy Offer Hard Price Cap for Price Sensitive Demand Bids and Virtual Demand Bids.[116]

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[106] *Id*. at p. 45.

[107] *Id*.

[108] *Id*.

[109] *Id*. MISO also notes that it reviewed similar "circuit breaker" concepts applied by ERCOT and proposed by PJM. Ultimately, these existing concepts informed MISO's proposal.

[110] *Id*. at p. 43.

[111] *Id*.

[112] *Id*.

[113] *Id*.

[114] *Id*.

[115] *Id*.

[116] *Id*.

Removing the bid cap would allow day-ahead demand to specify a maximum bid price above $2,000/MWh.[117]

D. Need to Update Operating Reserve Demand Curve

1. Need for Operating Reserve Demand Curve Update

MISO considers it necessary to update the Operating Reserve Demand Curve ("ORDC") because the current ORDC does not properly increase for greater Operating Reserve shortage and reduces congestion-management effectiveness for small Operating Reserve shortage.[118] The ORDC is linked to VOLL, and is dominated by two fixed steps ($1,100 and $2,100).[119] The relatively flat shape/magnitude of the current ORDC, as well as its non-updated lower/upper bounds, hampers the ORDC's ability to produce prices that appropriately reflect shortage conditions of varying degrees[120] Prices should increase as reserve shortage increases, due to the higher probability of load being shed when Operating Reserve deficits are increasing.

On the one hand, the upper bound of the Operating Reserve Demand Curve should not be so high that prices are driven to VOLL well before load-shedding is initiated. The upper bound also should not be so high that managing congestion becomes overly difficult for small shortages (*i.e.*, it is necessary to balance reserve shortages and transmission constraint violations).

On the other hand, the lower bound should balance the needs of clearing sufficient reserves and managing congestion. The lower bound should not be so low that it is frequently cheaper to violate the Operating Reserve requirement, than to redispatch units with available reserves (*i.e.*, minimize transient shortages). The lower bound also should not be so low that it is cheaper to violate the Operating Reserve requirement, than to allow emergency resources to set price (*i.e.*, Emergency Offer Floors).

2. Approaches in Other RTOs/ISOs

ERCOT's markets have the closest construct to MISO's Operating Reserve Demand Curve. However, the current ERCOT market does not co-optimize reserves in the real time market. As a result, the ERCOT operating reserve demand curve functions as a price adder. In addition, ERCOT's operating reserve demand curve increases much earlier than MISO's, reaching $5,000 at 3,000 MW of cleared operating reserves. The MISO Operating Reserve Demand Curve remains at zero until Operating Reserves fall below 2,410 MW. MISO's Short Term Reserve and Up Ramp Capability products help prevent MISO from approaching Operating Reserve shortage. As

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117 *Id*.

118 *Id*. at p. 23.

119 *Id.*

120 *Id.*

explained by Mr. Joundi, MISO has not cleared less than 50 percent of the Operating Reserve requirement in the Real-Time Market.[121]

E. Need to Decouple EDR Offer Cap from Updated VOLL

In light of the proposed updates to the VOLL and to the Operating Reserve Demand Curve, MISO considered what changes may be appropriate for the EDR Offer cap that is currently pegged at the existing VOLL of $3,500/MWh.

1. Options That MISO Considered

MISO considered the following three options for changing the Tariff's rules on the EDR Offer cap:

- Retire/Remove the EDR construct entirely as no longer needed, as there are few EDRs in the market, and they are seldom used.
- Replace the EDR Offer cap with Order No. 831-style Offer validation processes used for non-EDRs.
- Adopt a fixed EDR Offer Cap decoupled from the VOLL.

2. MISO's EDR Cap Proposal

After stakeholder consultation, MISO adopted the third option for the present filing, *i.e.*, establishing a specific EDR Offer cap not linked to the updated VOLL. MISO proposes that the specific cap be the current value of $3,500/MWh. In effect, this maintains the status quo, instead of immediately doing away with EDRs due to low levels of market participation and use, or experimenting with offer validation processes used by non-EDRs. While MISO may soon seek the elimination of the EDR category through a separate Tariff filing that further refines the Tariff's rules on demand response, MISO deems it an appropriate interim step to decouple the EDR Offer Cap from the VOLL.

F. Stakeholder Discussions

MISO has engaged in a robust stakeholder process in which it solicited and obtained substantive feedback from multiple interested parties. As discussed by Mr. Ramey, shortage pricing issues, options, and proposals were discussed in MSC meetings, including the August 23, 2023, January 18, 2024, February 29, 2024, April 18, 2024, May 23, 2024, July 9, 2024, and August 22, 2024, MSC meetings.[122] In addition, stakeholder feedback requests were made at the

[121] *Id.* at p. 12.

[122] Ramey Testimony at p. 13, *fn* 13.

January 18, 2024, February 29, 2024, April 18, 2024, July 9, 2024, and August 22, 2024 MSC meetings.[123]

G. Continued IMM Monitoring and Reporting of Potential Physical Withholding

Section 53.1A of Module D of the Tariff, in conjunction with Section 64.1.1, provide for the required monitoring, audit, mitigation and reporting of any physical withholding that may occur during periods of shortage. MISO is not proposing any changes to these provisions.

H. Proposed Updates Regarding the VOLL

1. Proposed VOLL

As presented by Mr. Joundi, MISO proposes to distinguish two kinds of VOLL: (1) a Pricing VOLL of $10,000/MWh to be used as a price cap and an administrative price; and (2) a System VOLL of $35,000/MWh to be used to scale the ORDC.[124] The two VOLL values have different functions. The Pricing VOLL represents the price consumers are willing to pay to avoid an interruption of electrical service, and is mainly based on consumers with the lowest willingness to pay.[125] This Pricing VOLL is appropriate to use as a price cap (at all times) and also for fixed administrative pricing in EEA-Level 3 energy shortage conditions.[126]

The System VOLL represents the composite price that consumers are willing to pay to avoid an interruption of electrical service.[127] It is appropriate for scaling the Loss of Load Probability Curve for use in the Operating Reserve Demand Curve.[128] The updated values will ensure that MISO's shortage pricing rules maintain and enhance compliance with the Commission's requirement that shortage prices reflect load's willingness to pay to avoid service interruption under shortage conditions.[129]

As for the Pricing VOLL, MISO proposes to update the VOLL as a price cap (under sections 39.2.9.p, 40.2.15.p and 40.2.17.o) and for administrative pricing during MISO-directed EEA – Level 3 load-shed events (under sections 40.2.20.b.iii and 39.2.10.b of the Tariff). Mr. Joundi explains that the proposed Pricing VOLL of $10,000/MWh allows market prices to exceed the Willingness To Pay ("WTP") threshold for many loads, providing a clear financial incentive

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[123] *Id.*

[124] Joundi Testimony at p. 31.

[125] *Id*.

[126] *Id*.

[127] *Id*.

[128] *Id*.

[129] *Id*.

to reduce consumption.[130] In addition, this proposal is reasonable because it will incentivize the availability of incremental emergency supply from resources and interchange.[131] In addition, the proposed VOLL of $10,000/MWh, combined with the redesigned ORDC, provides room for all pricing components (*e.g*., Marginal Energy Component, Marginal Congestion Component, and Marginal Loss Component) before price capping.[132]

2. Methodology and Supporting Data

After considering several alternatives,[133] MISO developed an updated Pricing VOLL value by combining the methodology accepted by the ASM Order, and the methodology used by the IMM in making his recommendations. This approach seeks to estimate the price at which customers prefer interruption of their electrical service instead of the marginal cost of service, taking into account such variables as market segment (residential, commercial, industrial), temporal factors (time of day, season), duration and frequency of outages, and amount of advance notification of an outage.

MISO updated the VOLL calculations in late 2023 using recent econometric results, delineating multiple load characteristics and willingness to pay data.[134] These analyses utilized the Lawrence Berkely National Laboratory meta-analyses with MISO-specific drivers, consistent with the approach MISO used in its original determination of VOLL, and the IMM's recommendations.[135] This was similar to the original approach accepted by the ASM Order, because MISO's original VOLL study in 2005 was based on a precursor of the Berkely studies (Lawton and Sullivan 2001); and with the IMM's approach in his Recommendation 2016-1, which relied on the Berkely studies. As the IMM has pointed out, the survey studies create data using actual outage experiences of customers.

This approach uses two-step regression models to estimate statistically significant outage cost functions.[136] As a result of the analysis, hundreds of values for VOLL were updated, with

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[130] *Id*. at p. 32.

[131] *Id*. at p. 32.

[132] *Id*. at pp. 32-33.

[133] The approaches considered by MISO for updating the VOLL are summarized and evaluated in Appendix E to the Scarcity Pricing Whitepaper.

[134] Joundi Testimony at p. 35.

[135] *Id.* at pp. 35-36. ; *see Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, Berkeley Lab Energy Markets & Policy, https://emp.lbl.gov/publications/updated-value-service-reliability (last visited Oct. 31, 2024).

[136] Joundi Testimony at p. 36; Shortage Pricing White Paper, Appendix H ("Appendix H: Updated 2023 Value of Lost Load Calculations") at 41.

breakdowns for the following aspects where the highest VOLL factors are bolded in the figure below:[137]

Three customer load segments (Residential, **Small Commercial & Industrial**, Large Commercial & Industrial)	Three outage durations: **1 hour**, 2 hour, and 8 hour	Two seasons: **summer**, non-summer
Three time-of-day periods: afternoon, evening, **off-peak**	Commercial and Industrial sub-types: **manufacturing**, construction, or neither	State-level and MISO-wide aggregations

The 2023 MISO-wide, load weighted nominal values resulting from the updated analysis are provided in the figure below:[138]

Load Class	*1-hr outage*	*2-hr outage*	*4-hr outage*	*8-hr outage*	*12-hr outage*
Residential	$4,337	$2,420	$1,477	$1,013	$832
Small C&I	$80,965	$50,277	$37,006	$33,271	$31,098
Small C&I, Services #	$66,354	$41,227	$30,328	$27,267	$25,486
Large C&I	$29,472	$20,391	$18,194	$21,859	$24,054
System VOLL *	$36,889	$23,545	$18,342	$18,309	$18,342
Pricing VOLL using 2007 weightings (85% Residential / 15% Services)	**$13,639**	**$8,241**	**$5,804**	**$4,951**	**$4,530**

Basis of $10,000 VOLL for EEA events < 4 hrs (1-hr and 2-hr outage)

Basis of $5,000 VOLL for EEA3 events >=4 hrs (4-hr, 8-hr and 12-hr outage)

* Inter-class weights: 34% Large C&I, 31% Small C&I, 35% Residential
# Value reduced by 18% if only considering "Services" sub-category of Small C&I

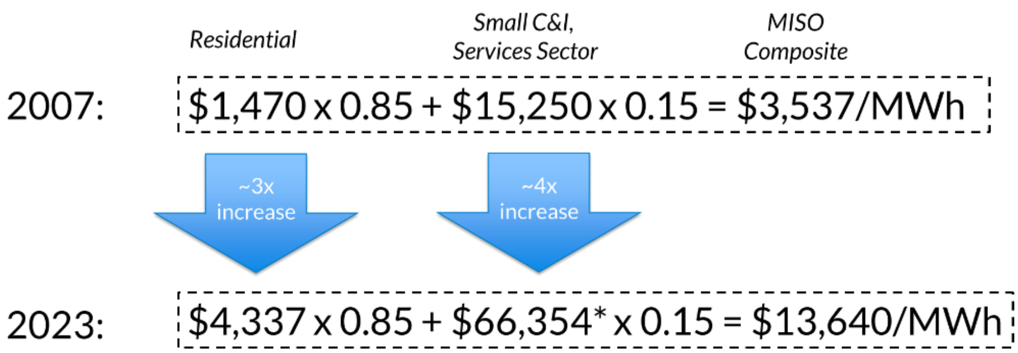
The $3,500/MWh represented an estimate of the VOLL that used an average of the median values for the residential class ($1,470), and the lowest median value of the small commercial and industrial classes ($15,250). The calculation of the average used weights of 0.85 for services to the residential class, and 0.15 for service to the small commercial and industrial classes. The

[137] Joundi Testimony at p. 36; Shortage Pricing White Paper, Appendix H ("Appendix H: Updated 2023 Value of Lost Load Calculations") at 41.

[138] Joundi Testimony at p. 37; Shortage Pricing White Paper, Appendix H ("Appendix H: Updated 2023 Value of Lost Load Calculations") at p. 43.

original VOLL value estimated the degree of "willingness to pay" of the market segment with the least valuation of uninterrupted electrical service *(i.e.*, the residential class), while also taking into account that loss of load will also impact market segments with a greater willingness to pay to avoid service interruption *(i.e.*, the small commercial and industrial classes).

As in the case of the original VOLL, MISO's updated VOLL calculation was guided by the same consumer class weightings on which the current VOLL was based, *i.e.*, eighty-five percent (85%) for the residential class and fifteen percent (15%) for the services sector of the small commercial and industrial class. Mr. Joundi explains that updating the 2007 VOLL components (Summer, 1-Hour outage, Off-peak) to 2023 values would support a VOLL increase in the range of 300-400%, *i.e.*, to $13,640/MWh. This is shown in the following calculation in the figure below:[139]



* *MISO estimated the services sector value, which was utilized in the 2007 VOLL calculation.*

MISO notes that the different customer load classes often share the same transmission and/or distribution circuits. Consequently, the Load Balancing Authorities ("LBAs"), which implement MISO's Load Shedding directives, are unable to exclusively target a single customer type (*e.g*., residential) to shed load. Instead, load-shedding plans of LBAs focus on reliability, and often consider factors aside from customer priorities. For example, LBAs consider their transmission and distribution grid technologies, interruptible rate programs, automated under-frequency load shedding systems, as well as other load characteristics.[140]

In this regard, in response to a recent MISO survey, LBAs indicated that the percentage of customer classes that would initially be shed in a wide area request are as follows:[141]

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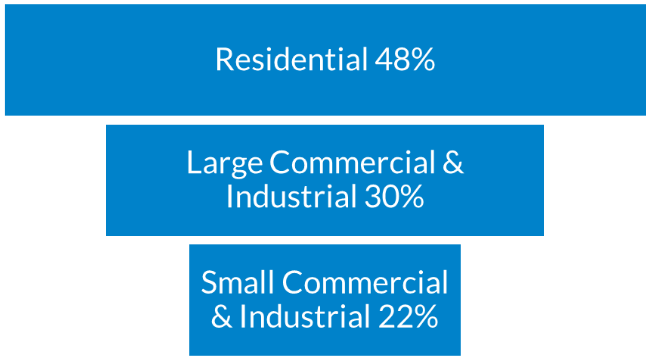
[139] *Id.* at p. 38; Shortage Pricing White Paper, Appendix H ("Appendix H: Updated 2023 Value of Lost Load Calculations") at 43-44.

[140] *Id*. at 44-45.

[141] *Id*. at 32.



MISO's proposed Pricing VOLL of $10,000/MWh recognizes that MISO-directed Load Shedding will be focused on the residential class, with a 1-hour-outage Summer VOLL of $4,337/MWh, but that other load classes would inevitably be dropped too. As shown above, even adding the lower proportion of 15 percent (instead of 52 percent) of non-residential load would result in a VOLL of $13,640/MWh. Indeed, if load were to be shed equally across all load types, a VOLL of $36,888 would be justifiable. After balancing various considerations, Mr. Joundi presents that MISO concluded that $10,000/MWh is a reasonable and appropriate value for the Pricing VOLL that will generate appropriate pricing signals without being punitive.[142]

Thus, MISO determined that it is reasonable to establish a Pricing VOLL of $10,000/MWh, as an administrative shortage price in EEA-Level 3 events with Load Shedding, and as an LMP/MCP price cap. This value appropriately reflects the latest data, reasonably gives greater weighting for residential load while recognizing the share of commercial and industrial loads, and avoids or reduces the risk of heavy financial burdens on Market Participants. This represents a low-end estimate of the negative financial impacts associated with MISO-directed firm Load Shedding, and can generate appropriate pricing signals without being excessively punitive.[143]

The proposed Pricing VOLL of $10,000/MWh provides a clear financial incentive to reduce consumption. This value is also expected to incent incremental emergency supply from resources and interchange. This updated VOLL, in combination with the proposed redesign of the Operating Reserve Demand Curve, will provide room for all pricing components – the Marginal Energy Component ("MEC"), Marginal Congestion Component ("MCC") and Marginal Loss Component ("MLC") – to come into play before market prices are capped.[144]

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[142] Joundi Testimony at p. 33; Shortage Pricing White Paper, at 11-12.

[143] Joundi Testimony at pp. 32-33.

[144] *Id.* at pp. 32-33.

3. Proposed Market Price Circuit Breakers

MISO proposes to include in the Tariff market price "circuit breakers" that will reduce the Pricing VOLL when the MISO-declared EEA-Level 3 Capacity Emergency lasts for an extended period (potentially hours to days).

First, at the end of four hours of real-time EEA – Level 3 load-shedding in a Max Gen Emergency, the real-time Pricing VOLL shall be reduced to $5,000/MWh.[145] This is based on the fact that the figure below shows that the Pricing VOLL drops between $4,530 and $5,804/MWh for outages lasting 4-12 hours.

2023 MISO-wide VOLL ($/MWh) components for key load classes and outage durations

Load Class	1-hr outage	2-hr outage	4-hr outage	8-hr outage	12-hr outage
Residential	$4,337	$2,420	$1,477	$1,013	$832
Small C&I	$80,965	$50,277	$37,006	$33,271	$31,098
Small C&I, Services #	$66,354	$41,227	$30,328	$27,267	$25,486
Large C&I	$29,472	$20,391	$18,194	$21,859	$24,054
System *	$36,889	$23,545	$18,342	$18,309	$18,342
System VOLL using 2007 weightings (85% Residential / 15% Services)	**$13,639**	**$8,241**	**$5,804**	**$4,951**	**$4,530**

Basis of $10,000 VOLL for EEA events < 4 hrs

Basis of $5,000 VOLL for EEA3 events >=4 hrs

 # Value reduced by 18% if only considering "Services" sub-category of Small C&I
** Inter-class weights: 34% Large C&I, 31% Small C&I, 35% Residential*

The Capacity shortage's duration will not be deemed ended, but rather only paused, when MISO declares an end to the EEA-Level 3 but declares that Capacity shortage conditions remain. The shortage's duration is deemed ended when MISO declares an end to Capacity shortage conditions.

Second, when the shortage conditions that led to a Max Gen Emergency with EEA – Level 3 persist when the Day-Ahead Market closes at 1030 Eastern Prevailing Time ("EPT"), the day-ahead and real-time Pricing VOLLs shall be reduced to $5,000/MWh for the next Operating Day.[146]

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145 *Id*. at p. 46.

146 *Id*. at p. 46.

Third, when the shortage conditions that led to the Max Gen Emergency continues to any additional Day-Ahead Market closing, the day-ahead and real-time Pricing VOLLs shall be reduced to $2,000/MWh for the next Operating Day.[147]

Fourth, when the day-ahead and/or real-time Pricing VOLLs have been reduced by a circuit breaker, they shall cease to apply after MISO has terminated the Max Gen Emergency. At that point, the Pricing VOLL, as a potentially applicable administrative price, shall be reset to $10,000/MWh. Furthermore, if the Max Gen termination occurs before 1030 EPT, the day-ahead and real-time Pricing VOLLs, as potentially applicable administrative prices, are reset to $10,000/MWh at the end of the current Operating Day.[148] If the Max Gen termination occurs after 1030 EPT, the Pricing VOLLs, as potentially applicable administrative prices, are reset to $10,000/MWh at the end of the next Operating Day.[149]

4. Examples of Application of Circuit Breakers

At the August 22, 2024, MSC, MISO provided the following examples of how the Pricing VOLL circuit breakers will apply in certain scenarios involving extended EEA-Level 3 conditions:

<table>
<tr><th>Day</th><th>Time (EPT)</th><th>MISO Max Gen Level</th><th>DA VOLL</th><th>RT VOLL</th><th>Use RT VOLL as RT EEA3 Admin Price?</th><th>Use RT VOLL as RT Price Cap?</th></tr>
<tr><td>1</td><td>0:00</td><td>Normal Ops</td><td rowspan="4">$10,000</td><td rowspan="3">$10,000</td><td rowspan="2">No (no declared EEA3)</td><td rowspan="2">Yes</td></tr>
<tr><td>1</td><td>2:00</td><td>Max Gen (not EEA3)</td></tr>
<tr><td>1</td><td>8:00</td><td rowspan="3">Max Gen Event Step 5 (EEA 3)</td><td rowspan="3">Yes (for declared EEA3 area)</td><td rowspan="3">Yes (for non-EEA3 area)</td></tr>
<tr><td>1</td><td>12:00</td><td rowspan="4">$5,000</td></tr>
<tr><td>2</td><td>0:00</td><td rowspan="3">$5,000</td></tr>
<tr><td>2</td><td>8:00</td><td>Max Gen (not EEA3)</td><td rowspan="4">No (no declared EEA3)</td><td rowspan="4">Yes</td></tr>
<tr><td>2</td><td>20:00</td><td>Normal Ops</td></tr>
<tr><td>3</td><td>All Day</td><td>Normal Ops</td><td>$2,000</td><td>$2,000</td></tr>
<tr><td>4</td><td>0:00</td><td>Normal Ops</td><td>$10,000</td><td>$10,000</td></tr>
</table>

I. Proposed Updates Regarding Operating Reserve Demand Curves

1. Proposed Operating Reserve Demand Curves

MISO proposes to change the Operating Reserve Demand Curve so that it will be lower for small shortages (to improve congestion management outcomes), and will increase as the Loss-of-Load Probability escalates, driving prices towards the Pricing VOLL as reserves are exhausted, while not overwhelming other pricing components (*e.g.*, marginal energy offer, other reserve demand curves, marginal congestion, and marginal losses).

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[147] *Id.* at p. 46.

[148] *Id.* at pp. 48-49.

[149] *Id.* at p. 49.

In this regard, MISO proposes changing the relationship of the VOLL to the Operating Reserve Demand Curve. MISO agrees with the IMM's recommendation (2016-1) to define the Operating Reserve Demand Curve based on a loss of load probability calculation, scaled to reflect the cost of shedding firm load. Based on updated data, Mr. Joundi explains that MISO agrees with the IMM's recommendation made in the 2023 State of the Market (2016-1) to define the ORDC based on a loss of load probability calculation, scaled to reflect the cost of shedding firm load. MISO proposes a scaling factor of $35,000/MWh, which will be called the System VOLL.[150]

MISO further proposes a $6,000/MWh upper limit for the Operating Reserve Demand Curve, to allow prices to appropriately rise towards VOLL as Operating Reserves are depleted. While the Operating Reserve Demand Curve should have a large impact during shortage conditions, there are other components that also impact energy prices, such as generator offers, four other reserve demand curves, congestion, and losses. A $6,000/MWh cap on the Operating Reserve Demand Curve allows sufficient room for these other pricing components to function ahead of MISO-directed Load Shedding, which triggers the updated $10,000/MWh administrative price (*i.e.*, the Pricing VOLL).[151]

MISO also proposes a two-step floor for the ORDC ($600 and $1,100), using the same Most Severe Single Contingency ("MSSC") breakpoint as the current ORDC. This is lower than the current $1,100 and $2,100 ORDC steps and will help MISO better manage congestion for small Operating Reserve shortages, while clearing nearly all the available reserve supply. Congestion management is enhanced by the lower ORDC floor, because the market can send better pricing and dispatch signals to resources that are contributing to transmission constraint overloads.[152]

The proposed floors were also selected to prevent undesirably low prices during declared system emergencies and when Short-Term Reserves ("STR") are scarce. The STR demand curve can reach $500, which is also the value of the Tier 1 Emergency Offer Floor. The $600 step ensures the Operating Reserves price does not fall below these values for small Operating Reserve deficits, when considering the $100 Contingency Reserve Offer Cap. Similarly, the $1,100 step ensures that the Operating Reserves price does not drop below the Tier 2 Emergency Offer Floor (plus the Contingency Reserve Offer Cap).[153]

2. Methodology and Supporting Data

a. Shape of Updated Operating Reserve Demand Curve

In establishing the overall shape of the updated Operating Reserve Demand Curve, MISO's basic assumption is that greater Operating Reserve shortages increase the probability of Load Shedding, which can be quantified with a Loss of Load Probability calculation that uses measured

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[150] *Id.* at p. 52.

[151] *Id*. at p. 52.

[152] *Id.* at pp. 52-53.

[153] *Id.* at p. 53.

uncertainties. MISO compared historical Look-Ahead Commitment ("LAC") and Real-Time Security Constrained Economic Dispatch ("RT-SCED") cases in order to capture Net Load and Generation Outage/Derate uncertainties within a 10-30 minute lead time. Then, a Monte Carlo simulation generated the Loss of Load Probability ("LOLP") distribution, for varying Contingency Reserve levels.[154]

An updated Operating Reserve Demand Curve was generated by scaling the Loss of Load Probability Curve with an appropriate VOLL, which MISO proposes to define as the Value of Lost Load-System ("System VOLL"),[155] to reflect both the Load Shedding costs, and the role of MISO Emergency Procedures. MISO proposes a $35,000/MWh System VOLL based on the MISO composite value of $36,888/MWh, representing the financial impact of shedding load across all customer classes (residential, small, and large commercial and industrial). This value is higher than the $10,000/MWh VOLL used as the price cap and administrative shortage pricing during Load Shedding, which gives more weight to residential loads because LBAs typically shed such load more than others due to lower cost impacts.

The following figure illustrates how the ORDC shape changes for different values of the System VOLL. Note that the bottom "$10K*LOLP" curve is quite shallow and only reaches ~$1,600/MWh at a 50% Operating Reserve shortage.[156] That pricing is too low given the priorities and actions that would be taken by MISO operations during such shortages.[157] The $35,000/MWh scaling (orange curve), established using the VOLL calculations above, escalates Operating Reserve shortage pricing more appropriately.[158]

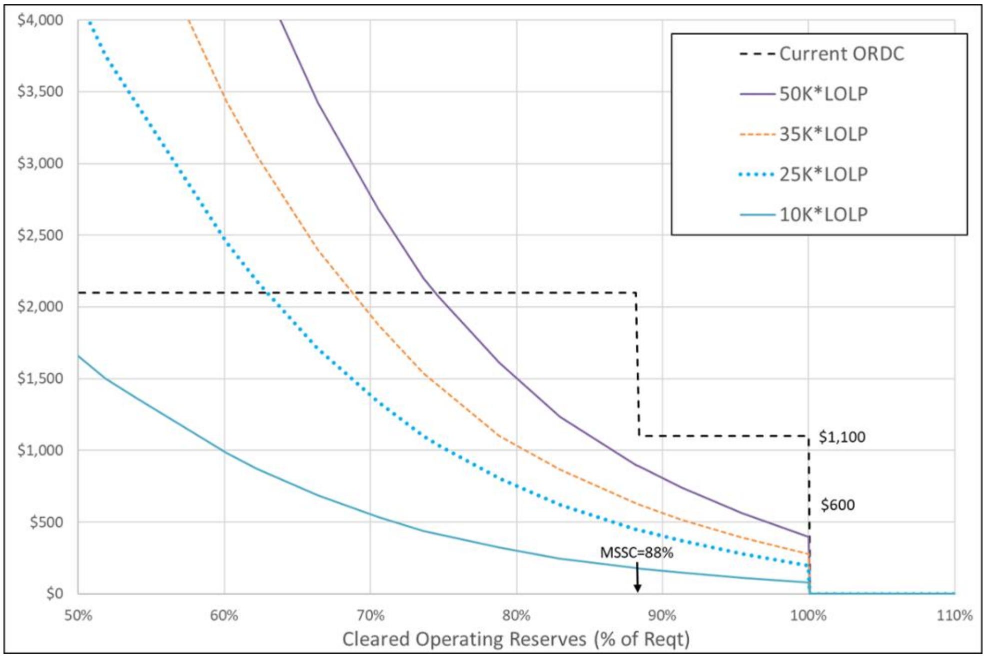
[154] *Id.* at p. 55. MISO's general framework for updating the Operating Reserve Demand Curve was described in the 2021 Scarcity Pricing Evaluation at 12-13 (§ 3.1.2).

[155] The Pricing VOLL was previously called the Operating Reserve Target Cost in the original Scarcity Pricing White Paper.

[156] *Id.* at p. 56.

[157] *Id.*

[158] *Id.*



When used as the scaling factor, the existing $3,500/MWh VOLL does not produce a gradually increasing curve in proportion to the degree of reserve shortage, and the price barely goes above $2,000/MWh even when the shortage reaches 50 percent. As explained by Mr. Joundi, the proposed Pricing VOLL of $10,000/MWh also produces a lower price barely reaching $1,600/MWh at a 50 percent Operating Reserve shortage.[159] Thus, it is more appropriate to use the proposed System VOLL of $35,000/MWh.[160]

b. Lower Bound of Updated Operating Reserve Demand Curve

MISO proposes an initial $600 step in the updated Operating Reserve Demand Curve to appropriately price transient Operating Shortages that are more "economic" in nature than reliability-related. The $600 ORDC lower bound was selected for several reasons. First, when MISO declares a Max Gen Warning or Maximum Generation Event Step 1, the market solution should not violate the Operating Reserve requirement to avoid clearing resources offered at the minimum Tier I Emergency Offer Floor. This is accomplished by setting the floor to be the sum of the minimum Tier I Emergency Offer Floor of $500/MWh and the Contingency Reserve Offer Cap of $100/MWh. Second, this floor greatly reduces Operating Reserve "economic shortages" compared to an even lower floor (previously $200/MWh). Third, the proposed floor acknowledges the potential combined pricing impact of Operating Reserve and STR shortages (*i.e.*, the impact of concurrent Operating Reserve and STR shortage could reach the current $1,100 ORDC step).

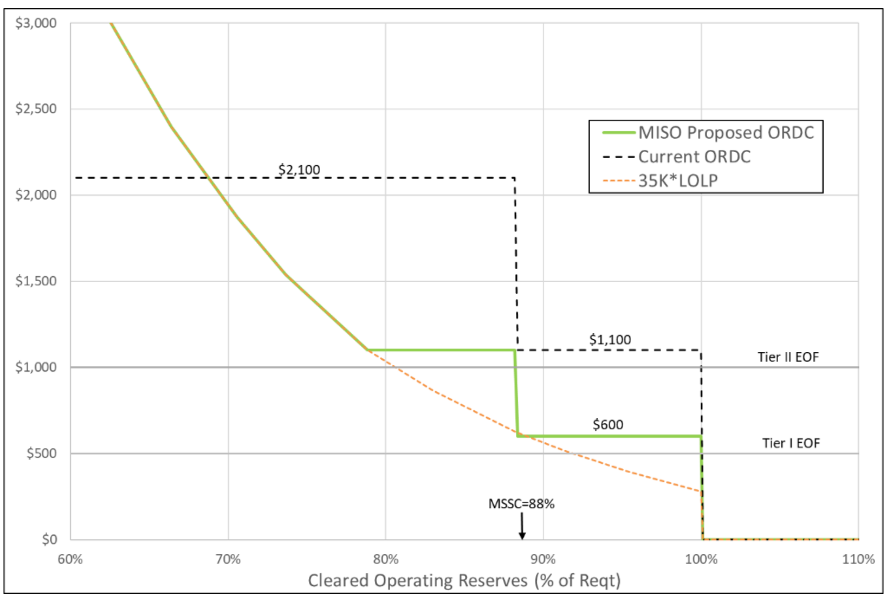
159 *Id.* at p. 56.

160 *Id.*

Fourth, by reducing the first step from $1,100 (current ORDC) to $600, MISO can better manage congestion during small Operating Reserve shortages.[161]

MISO also proposes an $1,100 Operating Reserve Demand Curve step when reserves fall below the Most Severe Single Contingency ("MSSC"). The $1,100 ORDC lower bound was selected for several reasons. First, this second step increases the shortage pricing when cleared Operating Reserves fall below the Most Severe Single Contingency, used in EOP-002 Step 4.2.9.4. Second, when MISO declares a Max Generation Event Step 2, the market solution should not violate the Operating Reserve requirement to avoid clearing resources offered at the minimum Tier II Emergency Offer Floor. This is accomplished by setting the floor to be the sum of the minimum Tier II Emergency Offer Floor of $1,100/MWh, and the Contingency Reserve Offer Cap of $100/MWh. Third, by reducing the second step from $2,100 (current ORDC) to $1,100, MISO can better manage congestion during small Operating Reserve shortages.[162]

With that background, MISO proposes an ORDC floor of $600/MWh when cleared Operating Reserves are above the MSSC (88%), and $1,100/MWh when cleared Operating Reserves are below the MSSC:[163]



MISO's proposed update to the ORDC is depicted in the chart below:[164]

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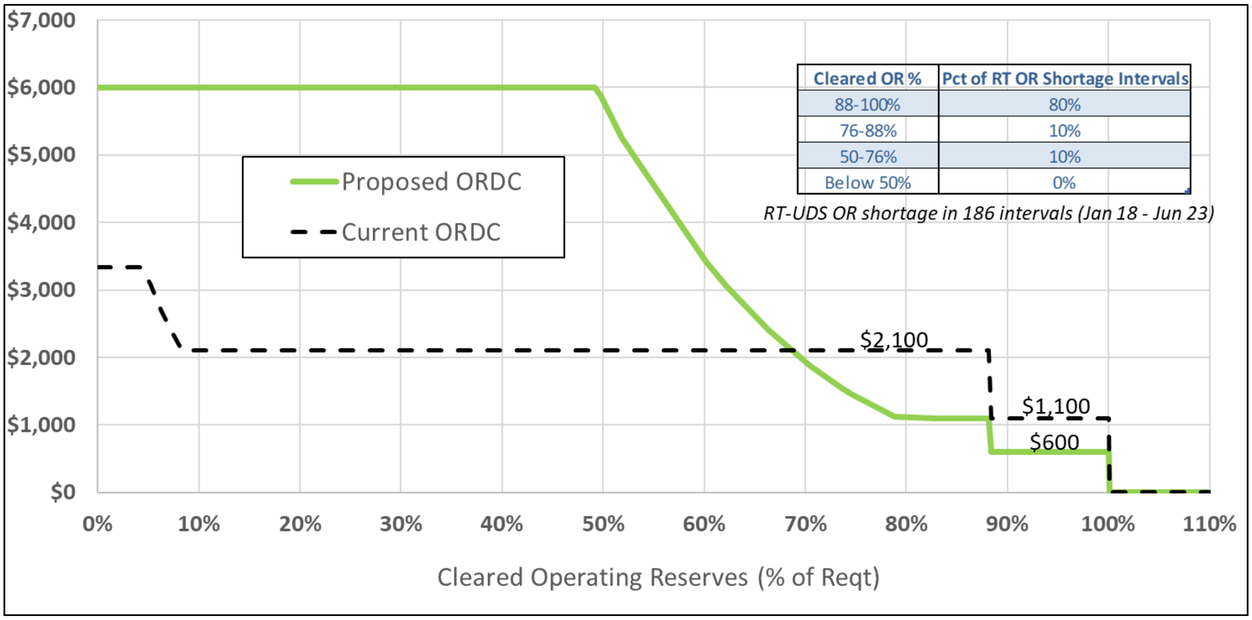
[161] *Id.* at p. 61.

[162] *Id.* at pp. 61-62.

[163] *Id.* at p. 58.

[164] *Id.* at p. 54.



c. Upper Bound of Updated Operating Reserve Demand Curve

MISO proposes an upper bound of $6,000/MWh for Operating Reserve Demand Curve. During extreme Operating Reserve shortages, high energy prices will incentivize beneficial demand response, increased imports, and additional energy production. As the Pricing VOLL is administratively applied during shortage events that lead to MISO-directed Capacity emergency load-shedding, prices should rise towards the Pricing VOLL before load-shedding begins and the Pricing VOLL is administratively applied. This upward price movement, prior to administrative application of the Pricing VOLL, is accomplished by ensuring that the ORDC escalates appropriately when deficits become severe, and that the ORDC upper bound is set sufficiently high. Additionally, the ORDC upper limit should allow sufficient room for other MEC contributions (*i.e.*, marginal energy offers and shadow prices from other reserve products) as well as LMP congestion and loss components. The current ORDC is very close to the existing VOLL, whose non-updated low level curtails many otherwise appropriate high LMPs during tight operating conditions.[165]

Accordingly, MISO proposes a $6,000/MWh upper bound for the ORDC. This upper limit ensures that, during severe reserve shortages, the energy prices will approach VOLL to encourage proper response from market participants. This ORDC upper bound also provides a margin of up to $4,000 for other MEC and LMP contributions to the energy prices, before the Pricing VOLL is applied.[166]

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165 *Id.* at p. 57.

166 *Id.*

3. Need to Decouple EDR Offer Cap from Updated VOLL

MISO's Emergency Demand Response ("EDR") product allows MISO to call on EDRs during a NERC Energy Emergency Alert 2 ("EEA - Level 2"), Alert 3 ("EEA - Level 3"), or any other type of emergency event. EDRs have only been deployed once, on September 24, 2014. EDRs make up a very small volume of MISO's available resources, often totaling less than 500 MW with notification times averaging over four hours.[167]

Schedule 30 of the Tariff currently defines the EDR Offer Cap as the VOLL. However, given the proposed increases to the Pricing VOLL, MISO has concerns that potential EDR offers capped at a much higher Pricing VOLL would overstate the relative value of EDRs, compared to other types of supply resources.[168]

In the short term, if changes are made to the VOLL, the EDR Offer Cap should remain at the current $3,500/MWh. Thus, MISO proposes that the EDR Offer Cap be fixed at the current level of $3,500/MWh, without tying it to the VOLL. On a long-term basis, MISO intends to work with stakeholders to improve how demand response can effectively be offered/utilized during emergency shortage conditions. As part of that improvement, MISO is contemplating the eventual removal of the EDR category, which the IMM recommends.

III. DESCRIPTION OF TARIFF REVISIONS

MISO is proposing the following Tariff revisions.

A. VOLL Updates

1. Pricing VOLL

a. Revised and Bifurcated Definition of VOLL

The existing term and definition of the VOLL is being replaced with the new term Pricing VOLL, and the new term System VOLL (defined *infra*) is also being introduced to distinguish the scaling factor used to determine the Operating Reserve Demand Curve.

The Pricing VOLL is defined as follows:

> The value that represents the price consumers are willing to pay to avoid an interruption of electrical service during a EEA-Level 3, which is based on consumers with the lowest willingness to pay. The Pricing VOLL shall default to $10,000/MWh, and shall be reduced when necessary as set forth in section 40.2.20.b.iv of this Tariff.

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[167] *Id*. at p. 63.

[168] *Id*. at p. 64.

b. Pricing VOLL as Administrative Price

Section 40.2.20.b.iii of the Tariff is being revised to require the Pricing VOLL to be used in the Real-Time Market in EEA-Level 3 Capacity Emergencies that result in Load Shedding.

Section 39.2.10.b ("Shortage Conditions in the Day-Ahead EORM") of the Tariff is also being revised to require the Pricing VOLL to be used in the Day-Ahead Market when Operating Reserve depletion necessitates the curtailment of Fixed Demand Bids and Fixed Export Schedules.

c. Pricing VOLL as Price Cap

Section 39.2.9.p ("Day-Ahead Ex Ante LMP, Day-Ahead Ex Post LMP, Day-Ahead Ex Ante MCP, and Day-Ahead Ex Post MCP Price Cap") is being revised to use the Pricing VOLL as the price cap in the Day-Ahead Market.

Section 40.2.15.p ("Real-Time Ex Ante LMP and Real-Time Ex Ante MCP Price Cap") and section 40.2.17.o ("Real-Time Ex Post LMP and Real-Time Ex Post MCP Price Cap") of the Tariff are being revised to make the Pricing VOLL the *ex ante* and *ex post* price cap in the Real-Time Market.

2. Circuit Breakers

Section 40.2.20.b.iv is being added to the Tariff to provide that in a MISO-declared EEA-Level 3 Capacity Emergency where the Pricing VOLL of $10,000/MWh has been applied, that value shall be adjusted, or reset, under certain conditions.

First, the Pricing VOLL for the Real-Time Market shall be reduced to $5,000/MWh once the cumulative duration of the Capacity shortage conditions that led to the EEA-Level 3 reaches four (4) hours. The cumulative duration is deemed paused when MISO declares an end to the EEA-Level 3, but Capacity shortage conditions remain, as declared by MISO. Such cumulative duration is reset when MISO declares an end to Capacity shortage conditions.

Second, the Pricing VOLL shall be reduced to $5,000/MWh when Capacity shortage conditions that precipitated the EEA-Level 3 persist at the time the Day-Ahead Market closes. In such a situation, the $5,000/MWh Pricing VOLL shall be applied on the next Operating Day for both the Day-Ahead Market and the Real-Time Market (Sections 40.2.15.p and 40.2.17.o). Section 39.1.1 of the Tariff is also being revised to allow MISO to extend or reopen the Day-Ahead Market when the Capacity shortage conditions that precipitated the EEA-Level 3 persist.

Third, the Pricing VOLL shall be reduced to $2,000/MWh for both the Day-Ahead Ahead Market and the Real-Time Market for the next Operating Day(s), if the Capacity shortage conditions that precipitated the EEA-Level 3 continue at the close of any additional Day-Ahead Market(s). Section 39.1.1 of the Tariff is also being revised to allow MISO to extend or reopen the Day-Ahead Market when the Capacity shortage conditions that precipitated the EEA-Level 3 persist.

Fourth, after the shortage conditions described in the three preceding paragraphs have ended, the Pricing VOLL shall be reset to the initial value of $10,000/MWh. This resetting shall occur at the end of the current Operating Day, if MISO declares an end to the Capacity shortage conditions before the close of the Day-Ahead Market; or at the end of the next Operating Day, if MISO declares an end to the Capacity shortage conditions after the close of the Day-Ahead Market.

3. Day-Ahead Price-Sensitive Bids and Virtual Demand Bids

MISO is revising section 39.2.2.c.ii ("Price Sensitive Demand Bid Data") and section 39.2.4.b ("Virtual Bid Components") of the Tariff to remove the $2,000/MWh cap because the cap is unnecessary and inappropriate for these types of bids.

B. Operating Reserve Demand Curve Updates

1. System VOLL and Loss of Load Probability Curve

MISO is adding the term System VOLL to the Tariff. The System VOLL is defined as follows:

> The value that represents the price consumers are willing to pay to avoid an interruption of electrical service. The System VOLL shall be equal to $35,000/MWh, and shall be used to scale the Loss of Load Probability Curve when calculating the Operating Reserve Demand Curve specified in Schedule 28.

MISO is also adding the term Loss of Load Probability Curve, defined as follows:

> The probability of losing Load under varying levels of Contingency Reserve shortages, to be used in accordance with Schedule 28.

2. Revised Operating Reserve Demand Curve

Section III ("Market-Wide Operating Reserve Demand Curve") of Schedule 28 of the Tariff ("Demand Curves for Operating Reserve, Regulating and Spinning Reserve, and Regulating Reserve, Up Ramp Capability, Down Ramp Capability, and Market-Wide Short-Term Reserve") is being revised to state the following rules on the Operating Reserve Demand Curve.

First, if the cleared Operating Reserve level is less than the minimum of (100%, or the percentage amount required to satisfy the Most Severe Single Contingency as determined by the Reserve Sharing Group), the price is the product of the System VOLL and the Loss of Load Probability Curve (as further described in MISO's Business Practices Manuals or "BPMs"). The maximum price is $6,000/MWh. The minimum price is $1,100/MWh, which is the sum of $1,000 (the lower bound of the Emergency Tier II Offer Floor) and the $100 Contingency Reserve Offer Price Cap.

Second, if the cleared level is less than 100% of the requirement level, but greater than or equal to the percentage amount required to satisfy the Most Severe Single Contingency, as defined by NERC, and as determined by the Reserve Sharing Group, the price is $600/MWh, which is the sum of $500 (the lower bound of the Emergency Tier I Offer Floor) and the $100 Contingency Reserve Offer Price Cap. This will not apply when the percentage amount required to satisfy the Most Severe Single Contingency as determined by the Reserve Sharing Group exceeds or equals 100% of the requirement level.

Third, the System VOLL shall be $35,000 per MWh. As stated in the definition of the System VOLL, it shall be used to scale the Loss of Load Probability Curve in calculating the Operating Reserve Demand Curve.

C. EDR Changes

Section IV ("EDR Offer") of Schedule 30 of the Tariff ("Emergency Demand Response Initiative") is being revised to cap EDR Offers at the specific amount of $3,500/MWh, instead of identifying or linking the cap with the Pricing VOLL.

D. Continued Market Monitoring, Mitigation and Reporting of Physical Withholding Under Shortage Conditions

The proposed updates to the VOLL and Operating Reserve Demand Curves, and the change to the EDR Offer Cap, do not necessitate any changes to the provisions of section 53.1A, in relation to section 64.1.1, of Module D of the Tariff on the IMM's monitoring, audit, mitigation and reporting of any physical withholding that may occur during periods of shortage.[169]

IV. DOCUMENTS SUBMITTED IN THIS FILING

The documents being submitted with this filing, in addition to this transmittal letter, are the following:

Tab A – Redlined Tariff sheets effective September 30, 2025[170]

Tab B – Clean Tariff sheets effective September 30, 2025

Tab C – Testimony of Todd Ramey

Tab D – Testimony of Zakaria Joundi

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169 ASM Order at PP 151-155, 212-214.

170 MISO has removed language that has a future effective date of 6/1/2029 and is pending under Docket No. ER22-1640-003. If needed, MISO commits to make a subsequent filing with the Commission to reflect the most up-to-date version of the then-current Tariff provisions prior to the effective date of the language in Docket No. ER22-1640-003.

Tab E – Affidavit of David B. Patton, Ph.D.

V. Effective Date and Request for Extended Comment Period

MISO requests that these Tariff revisions be made effective on Operating Day September 30, 2025. For purposes of this requested effective date, MISO requests the Commission to grant waiver of its regulations in 18 CFR §35.3(a)(1) requiring that proposed revisions to rate schedules be filed no earlier than 120 days before their requested effective date. Good cause exists to grant this waiver because MISO needs adequate time, after acceptance of the proposed Tariff revisions, to make and test software and other operational adjustments needed to implement the proposed changes regarding VOLL, Demand Curves, and EDRs. In addition, MISO requests expedited resolution of the proposed Tariff revisions by April 1, 2025, so that MISO can budget and prepare in advance for such software, operational and other adjustments to ensure readiness to implement these revisions by September 30, 2025. MISO requests an extended comment period of forty-five (45) days in recognition of the upcoming holiday season and to facilitate stakeholders' review and comment on this proposal.

VI. Communications

All correspondence and communications in this matter should be addressed to:

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VII. Notice and Service

MISO has served a copy of this filing electronically, including attachments, upon all Tariff Customers, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, as well as all state commissions within the region. The filing has been posted electronically on MISO's website at https://www.misoenergy.org/legal/ferc-filings/ for other parties interested in this matter.

MISO also requests waiver of Section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13 (2020), to the extent applicable to this filing, and requests waiver of any other applicable requirement of 18 C.F.R. Part 35 for which waiver is not specifically requested, if necessary, in order to permit Commission acceptance of this filing.

VIII. CONCLUSION

MISO requests that the Commission accept the proposed Tariff revisions for filing, grant the effective date for Operating Day September 30, 2025, and grant waiver of any regulation deemed applicable to this filing to the extent necessary in order for the Commission to accept it as proposed.

Very truly yours,

/s/ Daniel M. Malabonga
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/Attachments

Tab A

Eastern Interconnection: The ERO certified Balancing Authorities operating in the eastern part of North America.

Eastern Prevailing Time (EPT): Eastern Daylight Time during periods when the eastern time zone is observing daylight saving time, Eastern Standard Time during periods when the eastern time zone is observing standard time.

Economic Maximum Dispatch: The maximum MW level at which a Resource may be dispatched by the Transmission Provider in real-time for Energy under normal system conditions. For Intermittent Resources or Resources incapable of following Setpoint Instructions, the Economic Maximum Dispatch will equal the Actual Energy Injections.

Economic Minimum Dispatch: The minimum MW level at which a Resource may be dispatched by the Transmission Provider in real-time for Energy under normal system conditions. For Intermittent Resources or Resources incapable of following Setpoint Instructions, the Economic Minimum Dispatch will equal the Actual Energy Injections.

Effective Import Tie Capability (EITC): The maximum aggregate level of power in MW that can be reasonably expected to flow on the transmission tie lines into a specified Zone of the Transmission System, while maintaining reliable operation.

Effective Export Tie Capability (EETC): The maximum aggregate level of power in MW that can be reasonably expected to flow outward on the transmission tie lines of a specified Zone of the Transmission System, while maintaining reliable operation.

Electric Distribution Company (EDC): A company that distributes electricity to retail customers through distribution substations and/or lines owned by the company.

Electric Facility: Equipment used for the generation, transmission, storage, or control of the transmission of electricity and that is connected to or part of the Transmission System operated by the Transmission Provider.

Electric Generation and Transmission Cooperative (Coop): An electric Generation and Transmission cooperative is a not for profit rural electric system whose primary function is to provide electric power on a wholesale basis to its owners.

Electric Reliability Organization (ERO): The organization certified by the Commission to establish and enforce reliability standards for the bulk-power system, subject to Commission review.

Electric Storage Resource (ESR): A Resource capable of receiving Energy from the Transmission System and storing it for later injection of Energy back to the Transmission System. This definition includes all technologies and/or storage mediums, including but not limited to, batteries, flywheels, compressed air, and pumped-hydro. The location of an ESR may be at any point of grid interconnection, on either the Transmission System or a local distribution system, but must not be outside the Transmission Provider Region. An ESR must: (1) be capable of injecting and withdrawing a minimum of 0.1 MW; (2) be capable of complying with the Transmission Provider's Setpoint Instructions; (3) have the appropriate metering equipment installed; and (4) be physically located within the MISO Balancing Authority Area. The State of Charge shall be managed by the Market Participant operating the ESR. An ESR shall also be deemed a Generator based on, and in contexts relevant to, its capability to inject Energy back into the Transmission System.

Electric Storage Resource Efficiency Factor: An operating characteristic of an Electric Storage Resource that is the amount of increase in Energy Storage Level for each 1 MWh of Charge Energy withdrawn by that Resource.

Electric Storage Resource Offer: An Offer submitted by a Market Participant within the MISO Balancing Authority Area for the output of a specified Electric Storage Resource to supply Energy, Capacity, Online Short-Term Reserve, Up Ramp Capability, Down Ramp Capability, Spinning Reserve, Supplemental Reserve and/or Regulating Reserve to the Energy and Operating Reserve Markets.

Electric Storage Resource Owner: An entity that owns, leases with rights equivalent to ownership in, and controls the output of or operates Electric Storage Resources.

Electric Storage Resource Transaction: Market Activities associated with the charging and discharging process of an Electric Storage Resource that consist of the withdrawal of Energy from the Transmission System, including any associated Energy purchases, and future injection of Energy, including any associated Energy sales, to the Transmission System under this Tariff.

Elemental Pricing Node (EPNode): A single Bus where LMP is calculated.

Eligible Confirmed Transmission Service Reservation: Any reservation for Transmission Service that has been confirmed and has a start date later than the date a Default first occurs. Any reservation for Transmission Service that has been confirmed remains a conditionally approved request at all times prior to such reservation's start date and may be cancelled if a Default occurs prior to such start date.

Eligible Customer: (i) Any electric utility (including the Transmission Owner(s), ITC Participants(s), and any power marketer), Market Participant, Federal Power Marketing Agency, or any person generating electric Energy for sale or for resale is an Eligible Customer under this Tariff. Electric Energy sold or produced by such entity may be electric Energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by § 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that a Transmission Owner or ITC Participant offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner or ITC Participant; or (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that a Transmission Owner or ITC Participant offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner or ITC Participant, that is an Eligible Customer under this Tariff. Unbundled retail customers that seek to take local distribution service cannot be Eligible Customers under this Tariff with respect to that service.

Eligible Projects: Shall mean any Market Efficiency Projects ("MEP") and Multi-Value Projects ("MVP") approved by the Transmission Provider's Board after December 1, 2015 regardless of whether such project is subject to the Transmission Provider's Competitive Developer Selection Process.

Emergency**:** (i) An abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm Load, equipment damage, or tripping of system elements that could adversely affect the reliability of any electric system or the safety of persons or property; (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of Emergency procedures as defined in this Tariff.

Emergency Demand Response (EDR): The commitment and dispatch of Load reductions, Behind the Meter Generation Resources and other Demand Resources during an Emergency, in accordance with Schedule 30.

EDR Dispatch Instruction: Directives issued by the Transmission Provider to EDR Participants indicating MW quantities to be reduced during Emergencies.

EDR Initiative: Procedures for EDR Participants to respond to an Emergency through a defined reduction in Load or increase in output from Behind the Meter Generation Resources, as described in Schedule 30 of this Tariff.

EDR Offer: An offer made by an EDR Participant to reduce demand in response to an Emergency event which will not be considered in the clearing of the Day-Ahead Energy and Operating Reserve Market or Real-Time Energy and Operating Reserve Markets.

EDR Participant: A Market Participant capable of reducing demand in response to directives received from the Transmission Provider during an Emergency event.

Emergency Energy: Purchases of Energy coordinated by the Transmission Provider following the issuance of an Energy Emergency Alert in accordance with the procedure set forth in Section 40.2.22 of this Tariff.

Emergency Maximum Energy Storage Level: State of Charge value that should not be exceeded when an Electric Storage Resource is being Charged while providing Energy or Operating Reserves under Emergency conditions.

Emergency Minimum Energy Storage Level: State of Charge value that should not be exceeded when an Electric Storage Resource is being Discharged while providing Energy or Operating Reserves under Emergency conditions.

Emergency Operating Procedures: Procedures coordinated by the Transmission Provider prior to and during Energy Emergencies.

Emergency Operations Resource: An online Generation Resource that is not an online Fast Start Resource and is started, synchronized and injects Energy, or a Demand Response Resource that reduces its Energy consumption, within two hundred forty (240) minutes of being notified and that has a minimum run time of less than four hours and that will participate in setting price as described in the process in Schedule 29A of this Tariff.

Emergency Operations Resource All-In Energy Offer: The sum of an online Emergency Operations Resource's Energy Offer, its amortized No Load Offer and, during its Minimum Run Time, its amortized Start up Offer; provided, that, in the case of a Demand Response Resource – Type I, it shall be the sum of the Energy Offer, its amortized Hourly Curtailment Offer and its amortized Shut-Down Offer over its minimum interruption duration.

Emergency Operations Resource All-In Reference Level: The sum of an online Emergency Operations Resource's Energy Reference Level, its amortized No Load Reference Level and, during its Minimum Run Time, its amortized Start up Reference Level; provided, that, in the case of a Demand Response Resource – Type I, it shall be the sum of the Energy Reference Level, its amortized Hourly Curtailment Offer Reference Level and its amortized Shut-Down Offer Reference Level over its minimum interruption duration.

Emergency System Conditions: Are (i) situations in which a systemic equipment malfunction, including telecommunications, hardware, or software failures, prevents the Transmission Provider from operating the Energy and Operating Reserve Markets in accordance with the Market Rules; or (ii) widespread electric transmission or generation equipment outages that prevent the Transmission Provider from dispatching the system in accordance with the Market Rules.

Emergency Tier I Offer Floor: The minimum Proxy Offer established by the Transmission Provider, as specified in Schedule 29A, following the declaration of maximum generation emergency warning as specified in the Transmission Provider's Emergency Operating Procedures. The maximum value of the Emergency Tier I Offer Floor will be the Energy Offer Hard Price Cap.

Emergency Tier II Offer Floor: The minimum Proxy Offer established by the Transmission Provider, as specified in Schedule 29A, following the declaration of maximum generation emergency event, step 2 as specified in the Transmission Provider's Emergency Operating Procedures. The maximum value of the Emergency Tier II Offer Floor will be the Energy Offer Hard Price Cap.

Energy: An amount of electricity that is Bid or Offered, produced, purchased, consumed, sold, injected, withdrawn, or transmitted over a period of time and measured or calculated in megawatt hours (MWh).

Energy and Operating Reserve Market(s): The Day Ahead and/or Real Time Energy and Operating Reserve Markets operated by the Transmission Provider.

Energy Consumer: Any end-use customer, including but not limited to commercial retail consumers of electricity, located within the Transmission Provider Region.

Energy Deficient Region: An area in which one or more LSEs within the MISO Balancing Authority Area are experiencing or are expected to experience an Emergency under the procedures specified under Section 40.2.20 of this Tariff.

Energy Efficiency Resource (EE Resource): A Planning Resource consisting of installed measures on retail customer facilities that achieves a permanent reduction in electric energy usage while maintaining a comparable quality of service.

Energy Emergency: A condition when a balancing authority can no longer meet the energy requirements of the firm end-use load within its balancing authority area and has initiated its Energy Emergency procedures**.**

Energy Emergency Alert: An alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area.

Energy Emergency Area: The area within a balancing authority area that is experiencing an Energy Emergency.

Energy Emergency Alert – Level 2 (EEA-Level 2): Energy Emergency Alert Level 2 as defined by NERC.

Energy Emergency Alert – Level 3 (EEA-Level 3): Energy Emergency Alert Level 3 as defined by NERC, indicating that firm load interruption is imminent or in progress.

Energy Management System (EMS): The software system used by the Transmission Provider and Transmission Operators for acquisition and processing of operational data.

Energy Market Counterparty: The Transmission Provider as the contracting counterparty to Market Participants for all Market Activities contemplated by this Tariff, solely in the Transmission Provider's capacity as a principal and not as an agent for any other party, consistent with the provisions of Section 6A.

Energy Offer: The price at which a Market Participant has agreed to sell the next increment of Energy from a Generation Resource, Demand Response Resource – Type I, Demand Response Resource-Type II, or the price at which a Market Participant has agreed to sell Energy via a Dispatchable Interchange Schedule Import Schedule; or the price at which a Market Participant has agreed either to import or export the next increment of Energy from an External Asynchronous Resource; or the price at which a Market Participant has agreed to either buy (Charge) or sell (Discharge) the next increment of Energy from an Electric Storage Resource.

Energy Offer Hard Price Cap: The maximum price permitted for a Verified Energy Offer, a Verified Fast Start Resource All-In Energy Offer, or a Verified Emergency Operations Resource All-In Energy Offer, to set price in the Energy and Operating Reserve Markets. The Energy Offer Hard Price Cap is $2,000/MWh.

Energy Offer Soft Price Cap: The maximum price permitted for an incremental Energy Offer, a Fast Start Resource All-In Energy Offer, or an Emergency Operations Resource All-In Energy Offer, to set price in the Energy and Operating Reserve Markets without prior cost verification by the Independent Market Monitor, subject to mitigation under Module

D when the Energy Offer, the Fast Start Resource All-In Energy Offer, or the Emergency Operations Resource All-In Energy Offer, cost exceeds the applicable Reference Level. The Energy Offer Soft Price Cap is $1,000/MWh. The Transmission Provider shall also verify Fast Start Resource All-In Energy Offers and Emergency Operations Resource All-In Energy Offers pursuant to section 64.1.4.a.iii.d of Module D.

Energy Offer Price Floor: The minimum price permitted for an Energy Offer in the Energy and Operating Reserve Markets.

Energy Resource Interconnection Service: The interconnection of a Generation Resource to the Transmission System or distribution system, as applicable, to be eligible to deliver the Generation Resource's electric output using the existing firm or non-firm capacity of the Transmission System on an as available basis.

Energy Storage Level: The stored Energy available to the Transmission Provider's markets for Energy or Operating Reserves from a Resource.

EPT: Eastern Prevailing Time.

Equity: For credit scoring purposes, the ownership interest in a firm, including the residual dollar value of a futures trading account, assuming its liquidation is at the going trade price of Applicant or Market Participant.

Equivalent Forced Outage Rate Demand (EFORd): The Equivalent Forced Outage Rate Demand, as defined by NERC.

EST: Eastern Standard Time.

Ex Ante MCP: The Regulating Reserve MCP, Regulating Mileage MCP, Spinning Reserve MCP, Supplemental Reserve MCP, Up Ramp Capability MCP, Down Ramp Capability

MCP, and Short-Term Reserve MCP calculated at the beginning of the Dispatch Interval, used for informational purposes in the Real-Time Energy and Operating Reserve Market.

Ex Post MCP: The Regulating Reserve MCP, Regulating Mileage MCP, Spinning Reserve MCP, Supplemental Reserve MCP, Up Ramp Capability MCP, Down Ramp Capability MCP, and Short-Term Reserve MCP calculated for each Dispatch Interval.

Excess Congestion Charge Fund: A fund established by the Transmission Provider representing, in aggregate, the difference between the total of all Transmission Congestion Payments for a given Hour and the hourly transmission congestion charges.

Excessive/Deficient Charge Rate: The rate used to determine a Resource's Excessive/Deficient Energy Deployment Charge as calculated pursuant to Section 40.3.4.b.

Excessive/Deficient Energy Deployment Charge: A charge assessed to any Resource in an Hour with Excessive Energy and/or Deficient Energy in four (4) or more consecutive Dispatch Intervals within the Hour.

Excessive Energy: The amount of a Generation Resource's, Electric Storage Resource's, or External Asynchronous Resource's Actual Energy Injection at a Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market in a Dispatch Interval that is greater than that Resource's Excessive Energy Threshold or, the amount of a Demand Response Resource's Type I Calculated DRR Type I Output, as adjusted for Actual Energy Injection or Demand Response Resource's Type II Calculated DRR Type II Output, at a Commercial Pricing Node in the Real Time Energy and Operating Reserve Market in a Dispatch Interval that is greater than that Resource's Excessive Energy Threshold.

Excessive Energy Threshold: The maximum value of a Resource's Tolerance Band.

Excessive Energy Tolerance: The MW difference between (1) the Excessive Energy Threshold and (2) the average of the Dispatch Targets for Energy for the current Dispatch Interval and the previous Dispatch Interval plus the average Regulating Reserve Deployment instruction for that Dispatch Interval.

Excessive Withdrawal: The amount of an Electric Storage Resource's Actual Energy Injection at a Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market in a Dispatch Interval that is less than the minimum of the Deficient Energy Threshold or zero (0).

Expected Unserved Energy (EUE): In the probabilistic study, an estimate of the energy that would otherwise have been used by end use customers but for a supply interruption.

Export Schedule: An Interchange Schedule in which the Interchange Schedule Receipt Point lies within the MISO Balancing Authority Area and the Interchange Schedule Delivery Point lies outside the MISO Balancing Authority Area.

Exporting Entity: A Market Participant that is not a Load Serving Entity with a cleared Export Schedule in the Day-Ahead Energy and Operating Reserve Market or an Export Schedule in the Real-Time Energy and Operating Reserve Market.

Extended Locational Marginal Price (ELMP): The Transmission Provider shall implement, ELMP, an enhanced pricing mechanism expanding upon LMP and MCP in which additional resources, including resources that are scheduled to operate at limits, certain off-line resources, and the start-up or shut-down and no-load or curtailment costs of resources may be included in the calculation of prices at the Commercial Pricing nodes located throughout the Transmission Provider region. Such prices shall be calculated per the process set forth in Schedule 29A.

Extended Transmission Outage: A Planned Transmission Outage that exceeds the original outage schedule previously provided by the Transmission Owner to the Transmission Provider.

External Asynchronous Resource: A Resource representing an asynchronous DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid that is supported within the Transmission Provider Region through Dynamic Interchange Schedules in the Day-Ahead Energy and Operating Reserve Market and/or Real-Time Energy and Operating Reserve Market. External Asynchronous Resources are located where the asynchronous tie terminates in the synchronous Eastern Interconnection grid.

External Resource: A generator located outside of the metered boundaries of the MISO Balancing Authority Area.

External Resource Zone (ERZ): A grouping of one or more External Resources in the same external balancing authority for purposes of the Planning Resource Auction.

Extreme Event: An event which includes, but is not limited to, extreme weather events, or other emergency events that have a severe short-term impact on market pricing. Such an event may be declared by the Transmission Provider in its sole discretion and shall affect the applicable Credit Policy calculations as set forth in within Attachment L.

Legitimate Risks: Business operation risks, incurred by a Market Participant, that increase as a result of providing any of the products described in the Tariff. These risks include, but are not limited to, the risk of repair expenses; business interruption due to outages resulting from either a failure to start, or unplanned outages that occur when the facility is in service; regulatory restrictions; and disruptions from labor relations problems. These risks are in the nature of marginal costs included in Reference Levels. In contrast, the risk associated with fuel purchase price is not a component of Reference Levels, but rather a basis for the Fuel Cost Uncertainty Adder and some of the conduct thresholds under Module D.

Letter of Credit: A Credit Support Document taking the form found in Exhibit II of Attachment L to this Tariff.

Line Outage Distribution Factor (LODF): The percent of flow on line A, which is transferred to line B for the loss of line A.

Load: A term that refers to either an end-user of Energy, net of system losses, or the amount of Energy (MWh) consumed by such end-user within the Transmission Provider Region.

Load Forecast: An estimate of the amount of Energy (MWh) or Capacity (MW) to be consumed within the Transmission Provider's Region, prepared by the Transmission Provider based upon input from Local Balancing Authorities and Load Serving Entities, and used in the Transmission Provider's scheduling and dispatch decisions to ensure reliable operation of the MISO Balancing Authority.

Load Modifying Resource: A Demand Resource or Behind the Meter Generation Resource.

Load Modifying Resource Market Participant (LMR MP): A Market Participant that has the rights to control the energy demand or the energy production from a Load Modifying Resource.

Load Ratio Share: Ratio of a Transmission Customer's Network Load in a Zone to the total Load in that pricing Zone computed in accordance with Module B, Section 34.2 of this Tariff.

Load Serving Entity (LSE): Any entity that has undertaken an obligation to serve Load for end-use customers by statute, franchise, regulatory requirement or contract for Load located within or attached to the Transmission System, including but not limited to purchase-selling entities and retail power marketers with the obligation to serve Load. Where a distribution cooperative or a municipal distribution system otherwise covered by the prior sentence is a wholesale customer of a generation and transmission cooperative or a municipal Joint Action Agency, the generation and transmission cooperative, a state or federal agency or municipal Joint Action Agency may act as the Load Serving Entity for such distribution cooperative or municipal distribution system. Where retail Load switching occurs in a state, the entity with the obligation to serve Load is the LSE

Load Shedding: The systematic reduction of system demand by temporarily decreasing Load in response to a Transmission System Emergency, Local Transmission Emergency, or MISO Balancing Authority Area or Sub-Area Capacity shortages, system instability, or voltage control considerations under Module B and Module C, of this Tariff.

Load Zone: A Zone determined by Market Participants representing an aggregate area of consumption for a single Load Serving Entity within the MISO Balancing Authority Area and used for the purposes of scheduling, reporting Actual Energy Withdrawal volumes, and settling Energy transactions at aggregated Load levels, approved and maintained by the Transmission Provider to facilitate transactions.

Local Balancing Authority (LBA): An operational entity or a Joint Registration Organization which is (i) responsible for compliance to NERC for the subset of NERC Balancing Authority Reliability Standards defined in the Balancing Authority Agreement for their local area within the MISO Balancing Authority Area, (ii) a Party to Balancing Authority Agreement, excluding MISO, and (iii) shown in Appendix A to the Balancing Authority Agreement.

Local Balancing Authority Area: Shall have the meaning set forth in the Balancing Authority Agreement.

Local Clearing Requirement (LCR): The minimum amount of Seasonal Accredited Capacity for an LRZ that is required to meet its LOLE for each Season while fully using the Zonal Import Ability for such LRZ and accounting for controllable exports.

Local Clearing Requirement Charge: A charge that is assessed to Load Serving Entities whenever an LRZ's Auction Clearing Price for a Season is increased due to its LCR being greater than the sum of individual Final PRMR of the LSEs.

Local Reliability Requirement (LRR): The minimum amount of Unforced Capacity for an LRZ to meet its LOLE for each Season, without considering transmission ties to systems outside of the LRZ.

Local Resource Zone (LRZ): A geographic area within the Transmission Provider Region that is prescribed by the Transmission Provider, based upon the criteria in Section 68A.3, to address congestion that limits Planning Resource deliverability.

Local Resource Zone Peak Demand: The Demand in MWs, for an LSE and/or EDC, in a Local Resource Zone that occurs coincident to the peak Demand for each Season in the Local Resource Zone, where all Demand has been augmented to include any known reductions in Demand related to LMRs and/or Energy Efficiency Resources.

Local Short-Term Reserve: Short-Term Reserve available to the Transmission Provider to address transmission constraints in any Reserve Zone(s).

Local Short-Term Reserve Requirements: The amount of Local Short-Term Reserve, as determined pursuant to Module C of the Tariff, that the Transmission Provider is required to procure in a Reserve Zone.

Local Transmission Emergency: Transmission System conditions or events that have the potential to exceed or have exceeded operating limits that do not pose a risk of cascading to the interconnection but require emergency-level actions.

Locational Marginal Price (LMP): A price for Energy at a given Commercial Pricing Node in the Transmission Provider Region which is the marginal cost of serving demand at the Commercial Pricing Node while meeting Zonal and Market-Wide Operating Reserve Requirements, Up Ramp Capability requirements, Down Ramp Capability requirements, and Short-Term Reserve Requirements. Such price may be either Ex Ante or Ex Post.

Long-Term Firm Point-To-Point Transmission Service: Firm Point To Point Transmission Service under Module B of this Tariff with a term of one (1) year or more.

Long Term Transmission Rights (LTTR): ARRs allocated in Stage 1A of the Annual ARR Allocation process. LTTRs carry annual rollover rights lasting ten (10) years or more.

Look Ahead Commitment (LAC): A process performed during the Real-Time Energy and

Operating Reserve Market that develops Resource commitment and decommitment options that may be used by the Transmission Provider to ensure sufficient Resources will be available to meet Load Forecast, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve and other demand requirements for the near term intra-hour intervals.

Loss of Load Expectation (LOLE): The sum of the loss of Load probability for the integrated daily peak Hour for each Day of the year.

Loss of Load Probability Curve: The probability of shedding firm Load under varying levels of Contingency Reserve shortages, to be used in accordance with Schedule 28. This curve is further described in the Transmission Provider's Business Practices Manual for the Energy and Operating Reserves Markets (BPM-002).

Loss Pools: A single Local Balancing Authority Area or an aggregation of Local Balancing Authority Areas, including those Local Balancing Authority Areas operated by Coordinating Owners consistent with the terms and provisions of the Coordinating Owners agreement, designated by the Transmission Provider for the purposes of calculating and distributing Day Ahead and Real Time Hourly Marginal Losses Revenue Surplus.

Lost Opportunity Cost: The LMP revenues that were not realized relative to a theoretical future operating point.

Value of Lost Load – Pricing (Pricing VOLL): The value that represents the price consumers are willing to pay to avoid an interruption of electrical service during a EEA-Level 3, which is based on consumers with the lowest willingness to pay. The Pricing VOLL shall default to $10,000/MWh, and shall be reduced when necessary, as set forth in section 40.2.20.b.iv of this Tariff.The maximum value associated with the Operating Reserve Demand Curve that represents the average cost to consumers of an interruption of firm demand as specified in Schedule 28.

Value of Lost Load – System (System VOLL): The value that represents the price consumers are willing to pay to avoid an interruption of electrical service. The System VOLL shall be equal to $35,000/MWh, and shall be used to scale the Loss of Load Probability Curve when calculating the Operating Reserve Demand Curve specified in Schedule 28.

Variance Analysis: Additional analysis performed by the Transmission Provider in accordance with Section IX of Attachment FF to the Tariff.

Verified Energy Offer: A Resource's cost-based incremental Energy Offer above the Energy Offer Soft Price Cap, verified by the Independent Market Monitor after the close of the Day-Ahead Energy and Operating Reserve Market or the Real-Time Energy and Operating Reserve Market and before market clearing.

Verified Fast Start Resource All-In Energy Offer: A Fast Start Resource All-In Energy Offer that exceeds the Energy Offer Soft Price Cap, and was verified by the Transmission Provider pursuant to section 64.1.4.a.iii.d of Module D before market clearing.

Virtual Bid: A bid to purchase Energy that is not backed by physical Load that is submitted in the Transmission Provider's Day Ahead Energy and Operating Reserve Market in accordance with the procedures and requirements of this Tariff.

Virtual Energy: Energy purchased and/or sold in the Day Ahead Energy and Operating Reserve Market that is not backed by real assets such as Load or Generation Resources.

Virtual Megawatt Hour Limit (Virtual MWh Limit): The limit on MWh of Virtual Bids and Virtual Supply Offers that may be submitted by a Tariff Customer on a given Operating Day, as established and modified pursuant to Section IV.A of Attachment L of this Tariff.

Virtual Supply Offer: An Offer to sell Energy that is not backed by a physical Resource that is submitted in the Transmission Provider's Day Ahead Energy and Operating Reserve Market in accordance with the procedures and requirements of this Tariff.

Virtual Transactions: Transactions related to Virtual Bids and/or Virtual Supply Offers.

Voltage and Local Reliability Commitment: A Transmission Provider issued Resource commitment in addition to, in lieu of or resulting from the Security Constrained Unit Commitment in the Day-Ahead Energy and Operating Reserve Market or any Reliability Assessment Commitment, in order to mitigate issues with Transmission System voltage or other local reliability concerns. These Resource commitment requirements are established prior to or during an Operating Day and are based on projected local reliability requirements, operational considerations, and generation and transmission outages. VLR Commitments will be based on Operating Guides for recurring voltage and local reliability requirements, but an Operating Guide is not required prior to a Resource commitment being designated as a VLR Commitment. Resource commitments to relieve a potential or actual IROL violation will not be designated in this category.

Voltage and Local Reliability Commitment Allocation Ratio: The ratio of RSG costs associated with Voltage and Local Reliability Commitments allocated to Local Balancing Authority Areas. The ratio is determined by the Transmission Provider as described in Schedule 44 of this Tariff.

Voltage and Local Reliability Local Balancing Authority Area Share: The pro rata allocation to each Local Balancing Authority Area of Revenue Sufficiency Guarantee Charges associated with Voltage and Local Reliability Commitments. The Voltage and Local Reliability Local Balancing Authority Area Share will be determined by the Transmission Provider as described in Schedule 44 of this Tariff.

Voltage and Reactive Power Coordination Procedures: The procedures that the Transmission Provider and the Congestion Management Customer shall establish to ensure the reactive power support necessary to maintain transmission voltages within limits that are established by the Transmission Provider, which are measured in MVAR.

Day-Ahead Energy and Operating Reserve Market Trading Deadline:

No later than the close of the Day-Ahead Energy and Operating Reserve Market, (1) Market Participants, including GFA Scheduling Entities and Market Participants with SSR Units, must submit to the Transmission Provider any Interchange Schedules, Bids for the purchase of Energy; Self-Schedules and/or Offers for the sale of Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, and Short-Term Reserve; and Offer Dispatch Status for Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve for consideration in the Day-Ahead Energy and Operating Reserve Market; and (2) Market Participants must indicate for each Hour of the Operating Day if Resources are to be self-committed or economically committed. The Day-Ahead Energy and Operating Reserve Market shall close at 1030 hours EPT, or such later time as may be required from time to time due to unanticipated events, the Day before the Operating Day. The Transmission Provider may extend or reopen the Day-Ahead Energy and Operating Reserve Market based on unanticipated events that: (i) interfere with the Transmission Provider's ability to receive or process Bid, Offer, or Interchange Schedule data; (ii) render Bid, Offer, or Interchange Schedule data plainly inaccurate in a manner that is likely to significantly impede the Transmission Provider's ability to deliver a feasible market solution; ~~or~~ (iii) are otherwise likely to have a widespread negative impact on the results of the Day-Ahead Energy and Operating Reserve Market, in a manner that adversely threatens or affects the reliability of market operations or of the Transmission System; or (iv) require adjustments to the Pricing VOLL in accordance with Section 40.2.20.b.iv. The Transmission Provider shall post a notice of any extension or reopening of the Day-Ahead Energy and Operating Reserve Market. The notice shall state each extension or reopening's circumstances, rationale, duration, and whether such action enabled the Transmission Provider to successfully address or minimize the issue that necessitated the extension or reopening.

Demand Bid Rules in the Day-Ahead Energy and Operating Reserve Market:

a. General Demand Bid Rules. Market Participants that intend to purchase Energy in the Day-Ahead Energy and Operating Reserve Market shall submit Fixed Demand Bids and/or Price Sensitive Demand Bids and shall provide the Bid information specified in this Section. Only Market Participants that have demonstrated to the Transmission Provider's satisfaction that they are Load Serving Entities or are purchasing on behalf of Load Serving Entities may submit Demand Bids. The Transmission Provider shall maintain a list of Commercial Pricing Nodes that may be specified in Demand Bids by Market Participants.

b. Fixed Demand Bid Components. Fixed Demand Bids shall include:

i. The Commercial Pricing Node registered by the Market Participant for which it intends to purchase the designated MWh of Energy.

ii. Hourly MWh quantities, with a default of zero (0) MWh.

c. Price Sensitive Demand Bid Data. Price Sensitive Demand Bids shall include:

i. Commercial Pricing Node registered by the Market Participant for which it intends to purchase the designated MWh of Energy.

ii. A maximum of nine (9) bid blocks for each Hour, where each Bid block specifies a maximum price ($/MWh), and MWh quantity. Price Sensitive Demand Bids may not exceed the Energy Offer Hard Price Cap.

a. **General Virtual Bid Rules.** Market Participants that intend to purchase Virtual Energy in the Day-Ahead Energy and Operating Reserve Market shall provide the Bid information specified in this Section. Market Participants may purchase Virtual Energy at any Commercial Pricing Node. Virtual Bids may not be used to purchase Operating Reserve.

b. **Virtual Bid Components.** Virtual Bids shall include:

i. The Commercial Pricing Node where the Market Participant desires to purchase the designated MWh of Energy.

ii. A maximum of nine (9) bid blocks for each Hour, where each Bid block specifies a maximum price ($/MWh) and MWh quantity. ~~Virtual Bids may not exceed the Energy Offer Hard Price Cap.~~

The Transmission Provider shall use SCUC, SCED, and SCED-Pricing algorithms to: (i) commit Resources; (ii) clear Offers, Bids, Self-Schedules, Interchange Schedules, and Virtual Transactions; (iii) establish Day-Ahead Schedules, Day-Ahead Ex Ante LMPs, and Day-Ahead Ex Ante MCPs; and (iv) establish Day-Ahead Ex Post LMPs and Day-Ahead Ex Post MCPs, for each Hour of the Operating Day.

a. Determination of Day-Ahead Schedules.

In the Day-Ahead Energy and Operating Reserve Market, the Transmission Provider shall determine: (i) Energy Schedules for Resources, Load Zones, Interchange Schedules, and Virtual Transactions; (ii) Operating Reserve Schedules for Resources; (iii) Up Ramp Capability and Down Ramp Capability Schedules for Resources; and (iv) Short-Term Reserve schedules for Resources.

b. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at Elemental Pricing Nodes.

The Transmission Provider shall calculate Day-Ahead Ex Ante LMPs for each Hour and Elemental Pricing Node in the Day-Ahead Energy and Operating Reserve Market using the SCED algorithm. The Day-Ahead Ex Ante LMP at an Elemental Pricing Node in a specific Hour is the marginal Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve and, if applicable, Reserve Scarcity costs, Up Ramp Capability scarcity costs, Down Ramp Capability scarcity cost, and/or Short-Term Reserve scarcity costs to supply Energy to Load at the Elemental Pricing Node during the Hour using the SCED algorithm. The Day-Ahead Ex Post LMPs will be based upon the SCED-Pricing algorithm described in Schedule 29A. The Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs are based on: (i) Generation Offers; (ii) Demand Response Resource–Type II Offers; (iii) External Asynchronous Resource Offers; (iv) Virtual Supply Offers; (v) Price Sensitive Demand Bids; (vi) Dispatchable Interchange Schedules; (vii) Up-to-TUC Interchange Schedules; (viii) Virtual Bids; (ix) Demand Curves; (x) Electric Storage Resource Offers; and (xi) Proxy Offers when appropriate as specified in Schedule 29A.

i. Calculation of Marginal Congestion Component.

For each Day-Ahead Ex Ante LMP and Day-Ahead Ex Post LMP, the Transmission Provider will calculate the Cost of Congestion at each Elemental Pricing Node as a component of the LMP (the Marginal Congestion Component). The Marginal Congestion Component of a Day-Ahead Ex Ante LMP reflects the marginal cost of managing transmission congestion and enforcing Sub-Regional Power Balance Constraints, that will arise from an incremental Energy demand at the Elemental Pricing Node supplied by an incremental Energy injection at the Reference Bus in the SCED algorithm. The Marginal Congestion Component of a Day-Ahead Ex Post LMP reflects the marginal cost of managing transmission congestion and enforcing Sub-Regional Power Balance Constraints, that will arise from an incremental Energy demand at the Elemental Pricing Node supplied by an incremental Energy injection at the Reference Bus in the SCED-Pricing algorithm.

ii. Calculation of Marginal Losses Component.

For each Day-Ahead Ex Ante LMP and Day-Ahead Ex Post LMP, the Transmission Provider will calculate the Cost of Losses at each Elemental Pricing Node as a component of the LMP at that Elemental Pricing Node (the Marginal Losses Component). The Marginal Losses Component of any Day-Ahead Ex Ante LMP reflects the marginal cost of serving System Losses that arise from an incremental Energy demand at the Elemental Pricing Node supplied by a loss adjusted Energy injection at the Reference Bus in the SCED algorithm. The Marginal Losses Component of any Day-Ahead Ex Post LMP reflects the marginal cost of serving System Losses that arise from an incremental Energy demand at the Elemental Pricing Node supplied by a loss adjusted Energy injection at the Reference Bus in the SCED-Pricing algorithm.

c. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at Aggregate Price Nodes.

The Transmission Provider shall calculate LMPs for each Hour and Aggregate Price Node in the Day-Ahead Energy and Operating Reserve Market. The calculation of LMPs for Aggregate Price Nodes will be based on the established normalized weighting factors for each Elemental Pricing Node defined in the Aggregate Price Node. The Aggregate Price Node LMP is equal to the sum of the products of the LMP at each Elemental Pricing Node and the associated normalized weighting factors for the Elemental Pricing Node.

d. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at Commercial Pricing Nodes.

The Transmission Provider shall establish relevant LMPs for each Hour and Commercial Pricing Node in the Day-Ahead Energy and Operating Reserve Market. The respective LMPs for Commercial Pricing Nodes, including the Marginal Congestion Component and Marginal Losses Component, shall be set equal to the respective LMP at the Elemental Pricing Node or Aggregate Price Node on which the Commercial Pricing Node is based.

e. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at a Resource Commercial Pricing Node.

The Transmission Provider shall determine the relevant LMP at a Resource Commercial Pricing Node as follows:

i. If the Resource has a single injection point and/or withdrawal point as in the case of an Electric Storage Resource, the relevant LMP for the Resource Commercial Pricing Node is set equal to the calculated respective LMP for the Elemental Pricing Node representing the Bus connected to the single injection or withdrawal point of the Resource.

ii. If the Resource has multiple injection points, that may or may not be connected to different Buses, the relevant LMP for the Resource Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Buses connected to each of the injection points of the Resource. The Aggregate Price Node weighing factors are specified by the Market Participant when the asset is registered.

f. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at a Load Zone Commercial Pricing Node

The Transmission Provider shall determine the relevant LMP for the Load Zone Commercial Pricing Node as follows:

i. If the Load Zone consists of a single Load, the relevant LMP for the Load Zone Commercial Pricing Node is set equal to the calculated respective LMP for the Elemental Pricing Node representing the Bus connected to the single Load.

ii. If the Load Zone consists of multiple Loads, the relevant LMP for the Load Zone Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Load Zone. The Aggregate Price Node representing the Load Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the Load Zone are connected.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the Load Zone's demand at the Elemental Pricing Node to the total demand of the Load Zone as determined by the results of the State Estimator from the average over the twenty-four (24) hours of seven (7) Days prior to the Operating Day.

g. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at a Hub Commercial Pricing Node

The Transmission Provider shall determine the relevant LMP for a Hub Commercial Pricing Node as follows:

i. If the Hub consists of a single Elemental Pricing Node, the relevant LMP for the Hub Commercial Pricing Node is set equal to the calculated respective LMP for the Elemental Pricing Node.

ii. If the Hub consists of multiple Elemental Pricing Nodes, the relevant LMP for the Hub Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Hub. The weighting factor for a specific Elemental Pricing Node is equal to a fixed normalized value determined by the Transmission Provider for the Hub, except as provided below for an ARR Zone administered as a Hub Commercial Pricing Node.

iii. Where an ARR Zone is administered as a Hub Commercial Pricing Node consisting of multiple Elemental Pricing Nodes, the relevant LMP for the Hub Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Hub. The Aggregate Price Node representing the ARR Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the ARR Zone are connected.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the ARR Zone's demand at the Elemental Pricing Node to the total demand of the ARR Zone as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operating Day.

h. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at an Interface Commercial Pricing Node

The Transmission Provider shall determine the relevant LMP for an Interface Commercial Pricing Node as follows:

i. If the Interface consists of a single Elemental Pricing Node, the relevant LMP for the Interface Commercial Pricing Node is set equal to the calculated respective LMP for the Elemental Pricing Node.

ii. If the Interface consists of multiple Elemental Pricing Nodes, the relevant LMP for the Interface Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Interface. The weighting factor for a specific Elemental Pricing Node is equal to a normalized value determined by the Transmission Provider for the Interface.

i. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Regulating Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources and External Asynchronous Resources

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante and Ex Post Regulating Reserve MCP for Generation Resources, Demand Response Resources – Type II, , Electric Storage Resources, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Regulating Reserve Constraint Shadow Price, (iv) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (v) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost of managing the transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Regulating Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

j. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Spinning Reserve Market Clearing Price for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources and External Asynchronous Resources

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, , Electric Storage Resources and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (iv) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

k. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Spinning Reserve Market Clearing Price for Demand Response Resources – Type I.

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve for Demand Response Resources – Type I for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm respectively, if such Demand Response Resources – Type I are eligible to provide Spinning Reserve as determined by Applicable Reliability Standards. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve for Demand Response Resources – Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

l. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Supplemental Reserve Market Clearing Price for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources and External Asynchronous Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve

Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

m. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Supplemental Reserve Market Clearing Price for Demand Response Resources - Type I

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve for Demand Response Resources - Type I for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve for Demand Response Resources - Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, and (ii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

n. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Up Ramp Capability Market Clearing Price

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Up Ramp Capability for qualified Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante

MCPs and Day-Ahead Ex Post MCPs for a Resource for Up Ramp Capability is the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Requirement Constraint is as set forth in Schedule 29 and Schedule 29A, respectively.

o. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Down Ramp Capability Market Clearing Price

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Down Ramp Capability for qualified Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Down Ramp Capability is the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint is as set forth in Schedule 29 and Schedule 29A, respectively.

p. Day-Ahead Ex Ante LMP, Day-Ahead Ex Post LMP, Day-Ahead Ex Ante MCP, and Day-Ahead Ex Post MCP Price Cap.

All Day-Ahead Ex Ante LMPs, Day-Ahead Ex Post LMPs, Day-Ahead Ex Ante MCPs, and Day-Ahead Ex Post MCPs will be capped at the Pricing VOLL.

q. Day-Ahead Offer Revenue Sufficiency Guarantee.

The Transmission Provider shall ensure the recovery of a Market Participant's Production Cost and Operating Reserve Cost for Resources committed by the Transmission Provider and scheduled in the Day-Ahead Energy and Operating Reserve Market, pursuant to Section 39.3.2B.

r. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Short-Term Reserve Market Clearing Price.

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Short-Term Reserve for qualified reserves for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCP and Day-Ahead Ex Post MCP for Short-Term Reserve are the applicable Cooptimized Zonal Short-Term Reserve Requirement constraint Shadow Prices.

If the sum of the fixed Demand Bids, Fixed Export Schedules, System Losses and Operating Reserve Requirements in the Day-Ahead Energy and Operating Reserve Market cannot be satisfied by the maximum non-Emergency supply level of all available non-Emergency Resources, Import Schedules and Virtual Supply Offers, the Transmission Provider shall clear the Day-Ahead Energy and Operating Reserve Market pursuant to the following procedures.

a. Step One. The Transmission Provider shall incorporate for use in the Day-Ahead Energy and Operating Reserve Market (i) the Market Participants' Offers submitted for each Generation Resource, Demand Response Resource – Type II, and External Asynchronous Resource up to the Hourly Emergency Maximum Limit, and up to the Hourly Emergency Maximum Discharge Limit and Hourly Emergency Minimum Energy Storage Level, except for Resources selected to provide Regulating Reserve, and (ii) the commitment of Generation Resources, Demand Response Resources - Type I, and Demand Response Resources - Type II that are designated as available for Emergency conditions only, and the commitment of Electric Storage Resources with a Commitment Status of Emergency Discharge, in amounts required to relieve the shortage condition in an economic manner. Day-Ahead Schedules, Ex Ante LMPs, and Ex Ante MCPs are then determined using the SCED algorithm. Ex Post LMPs and Ex Post MCPs are then determined using the SCED-Pricing algorithm, where Proxy Offers will be used as specified in Schedule 29A. Both SCED and SCED-Pricing algorithms will include Scarcity Pricing based on the Operating Reserve Demand Curves, Regulating and Spinning Reserve Demand Curves, and Regulating

Reserve Demand Curves if Operating Reserve is insufficient to meet the Market-Wide Operating Reserve Requirement following the release of Emergency Capacity described under (i) and (ii) above. Both SCED and SCED-Pricing algorithms will include Scarcity Prices based on the Market-Wide Short-Term Reserve Demand Curve if Short-Term Reserve is insufficient to meet the Market-Wide Short-Term Reserve Requirement following the release of Emergency Capacity described under (i) and (ii) above.

b. Step Two. If Operating Reserve is depleted and the Energy balance cannot be achieved after the process described in Step One above has been implemented, the Transmission Provider will curtail Fixed Demand Bids and Fixed Export Schedules in proportion to the scheduled amounts. Under this situation, all Energy and Operating Reserve will be priced at the Pricing VOLL.

The Transmission Provider shall (i) use a SCED algorithm to clear Offers, Self-Schedules, and Interchange Schedules, (ii) determine the MISO Balancing Authority NSI, and (iii) establish prices and physically binding Dispatch Targets for each Resource and Dispatch Interval.

a. Determination of Dispatch Targets

In the Real-Time Energy and Operating Reserve Market, the Transmission Provider shall determine Dispatch Targets for Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve for each Resource for the end of each Dispatch Interval.

b. Determination of the Real-Time Ex Ante LMPs at Elemental Pricing Nodes

The Transmission Provider shall calculate Real-Time Ex Ante LMPs for each Dispatch Interval and Elemental Pricing Node in the Real-Time Energy and Operating Reserve Market using the SCED algorithm. The Real-Time Ex Ante LMP at an Elemental Pricing Node in a specific Dispatch Interval is the marginal Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve and, if applicable, Reserve Scarcity costs, Up Ramp Capability scarcity costs, Down Ramp Capability scarcity costs, and/or Short-Term Reserve scarcity costs to supply Energy to a Load at the Elemental Pricing Node during the Dispatch Interval using the SCED algorithm. The Real-Time Ex Ante LMPs are established based on (i) Generation Offers, (ii) Demand Response Resource – Type II Offers, (iii) Electric Storage Resource Offers, and (iv) External Asynchronous Resource Offers.

i. Calculation of Marginal Congestion Component. The Transmission Provider will calculate the Cost of Congestion at each Elemental Pricing Node as a component of the Real-Time Ex Ante LMP (the Marginal Congestion Component).

The Marginal Congestion Component of a Real-Time Ex Ante LMP reflects the marginal cost of managing the transmission congestion and enforcing Sub-Regional Power Balance Constraints that will arise from an incremental Energy demand at the Elemental Pricing Node supplied by an incremental Energy injection at the Reference Bus in the SCED algorithm.

ii. Calculation of Marginal Losses Component. The Transmission Provider will calculate the Cost of Losses at each Elemental Pricing Node as a component of the Real-Time Ex Ante LMP at that Elemental Pricing Node (the Marginal Losses Component). The Marginal Losses Component of a Real-Time Ex Ante LMP reflects the marginal cost of serving System Losses that arise from an incremental Energy demand at the Elemental Pricing Node supplied by a loss adjusted Energy Injection at the Reference Bus in the SCED algorithm.

c. Determination of the Real-Time Ex Ante LMPs at Aggregate Price Nodes.

The Transmission Provider shall calculate Real-Time Ex Ante LMPs for each Dispatch Interval and Aggregate Price Node in the Real-Time Energy and Operating Reserve Market. The calculation of Real-Time Ex Ante LMPs for Aggregate Price Nodes will be based on established normalized weighting factors for each Elemental Pricing Node defined in the Aggregate Price Node. The Aggregate Price Nodes LMP is equal to the sum the products of the Real-Time Ex Ante LMP at each Elemental Pricing Node and the associated weighting factor for the Elemental Pricing Node.

d. Determination of the Real-Time Ex Ante LMPs at Commercial Pricing Nodes.

The Transmission Provider shall establish Real-Time Ex Ante LMPs for each Dispatch Interval and Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market. The Real-Time Ex Ante LMPs for Commercial Pricing Nodes, including the Marginal Congestion Component and Marginal Losses Component, shall be set equal to the Real-Time Ex Ante LMP at the Elemental Pricing Node or Aggregate Price Node on which the Commercial Pricing Node is based.

e. Determination of the Real-Time Ex Ante LMP at a Resource Commercial Pricing Node.

The Transmission Provider shall determine the Real-Time Ex Ante LMP at a Resource Commercial Pricing Node as follows:

i. If the Resource has a single injection point, the Real-Time Ex Ante LMP for the Resource Commercial Pricing Node is set equal to the calculated Ex Ante LMP for the Elemental Pricing Node representing the Bus connected to the single injection point of the Resource.

ii. If the Resource has multiple injection points, that may or may not be connected to different Buses, the Real-Time Ex Ante LMP for the Resource Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Buses connected to each of the injection points of the Resource. The Aggregate Price Node weighting factors are specified by the Market Participant when the asset is registered.

f. Determination of the Real-Time Ex Ante LMP at a Load Zone Commercial Pricing Node

The Transmission Provider shall determine the Real-Time Ex Ante LMP for the Load Zone Commercial Pricing Node as follows:

i. If the Load Zone consists of a single Load, the Real-Time Ex Ante LMP for the Load Zone Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Elemental Pricing Node representing the Bus connected to the single Load.

ii. If the Load Zone consists of multiple Loads, the Real-Time Ex Ante LMP for the Load Zone Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Load Zone.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the Load Zone's demand at the Elemental Pricing Node to the total Demand of the Load Zone, as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operation Day.

g. Determination of the Real-Time Ex Ante LMP at a Hub Commercial Pricing Node

The Transmission Provider shall determine Real-Time Ex Ante LMP for a Hub Commercial Pricing Node as follows:

i. If the Hub consists of a single Elemental Pricing Node, the Real-Time Ex Ante LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Elemental Pricing Node.

ii. If the Hub consists of multiple Elemental Pricing Nodes, the Real-Time Ex Ante LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Hub. The weighting factor for a specific Elemental Pricing Node is equal to a fixed normalized value determined by the Transmission Provider for the Hub, except as provided below for an ARR Zone administered as a Hub Commercial Pricing Node.

iii. Where an ARR Zone is administered as a Hub Commercial Pricing Node consisting of multiple Elemental Pricing Nodes, the Real-Time Ex Ante LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Hub. The Aggregate Price Node representing the ARR Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the ARR Zone are connected.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the ARR Zone's demand at the Elemental Pricing Node to the total demand of the ARR Zone, as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operating Day.

h. Determination of the Real-Time Ex Ante LMP at an Interface Commercial Pricing Node

The Transmission Provider shall determine Real-Time Ex Ante LMP for an Interface Commercial Pricing Node as follows:

i. If the Interface consists of a single Elemental Pricing Node, the Real-Time Ex Ante LMP for the Interface Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Elemental Pricing Node.

ii. If the Interface consists of multiple Elemental Pricing Nodes, the Real-Time Ex Ante LMP for the Interface Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Interface.

i. Determining the Real-Time Ex Ante Regulating Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources is equal to the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Regulating Reserve Constraint Shadow Price, (iv) Market-Wide Non-DRR1 Operating Reserve Constraint

Shadow Price, (v) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost for managing congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Regulating Reserve from the Reference Bus to the Reserve Zone; all such Constraints noted herein are as set forth in Schedule 29.

j. Determining the Real-Time Ex Ante Spinning Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (iv) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost for managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29. Such Spinning Reserved MCPs for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources shall be calculated on a real-time basis for each Dispatch Interval of the Real-Time Energy and Operating Reserve Market.

k. Determining the Ex Ante Spinning Reserve Market Clearing Price for Demand Response Resources – Type I

The Transmission Provider shall calculate the Ex Ante Spinning Reserve MCPs for Demand Response Resources – Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED algorithm, if such Demand Response Resources – Type I are eligible to provide Spinning Reserve as determined by Applicable Reliability Standards. The Spinning Reserve MCP for Demand Response Resources –Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29.

l. Determining the Real-Time Ex Ante Supplemental Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources is the sum of the (i) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (ii) Market-Wide Generation-based Operating Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29.

m. Determining the Real-Time Ex Ante Supplemental Reserve Market Clearing Price for Demand Response Resources - Type I

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Supplemental Reserve for Demand Response Resources - Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Supplemental Reserve for Demand Response Resources - Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, and (ii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29.

n. Determining the Ex Ante Up Ramp Capability Market Clearing Price

The Transmission Provider shall calculate the Real-Time Ex Ante Up Ramp Capability MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED algorithm. The Real-Time Ex Ante Up Ramp Capability MCP for a Resource is the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Constraint is as set forth in Schedule 29. Such Up Ramp Capability MCPs for Resources shall be calculated on a real-time basis for each Dispatch Interval of the Real-Time Energy and Operating Reserve Market.

o. Determining the Ex Ante Down Ramp Capability Market Clearing Price

The Transmission Provider shall calculate the Real-Time Ex Ante Down Ramp Capability MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED algorithm. The Real-Time Ex Ante Down Ramp Capability MCP for a Resource is the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Constraint is as set forth in Schedule 29. Such Down Ramp Capability MCPs for Resources shall be calculated on a real-time basis for each Dispatch Interval of the Real-Time Energy and Operating Reserve Market.

p. Real-Time Ex Ante LMP and Real-Time Ex Ante MCP Price Cap.

All Real-Time Ex Ante LMPs and Real-Time Ex Ante MCPs will be capped at the Pricing VOLL.

q. Determining the Ex Ante Regulating Mileage Market Clearing Price

The Transmission Provider shall calculate the Ex Ante Regulating Mileage MCPs for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market. The Ex Ante Regulating Mileage MCP for a Dispatch Interval is the highest Regulating Mileage Offer among all Resources that meet the following criteria: (1) if the Resource has a Day-Ahead schedule for cleared Regulating Reserve, then the Regulating Reserve Dispatch Status in the Day-Ahead Energy and Operating Reserve Market must be economic, (2) the Regulating Reserve Dispatch Status has to be economic in the Real-Time Energy and Operating Reserve Market, and (3)the Resource has a non-zero Dispatch Target for Regulating Reserve in that Dispatch Interval.

r. Determining the Real-Time Ex Ante Short-Term Reserve Market Clearing Price

The Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Short-Term Reserve for qualified reserves for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Short-Term Reserve is the applicable Co-optimized Zonal Short-Term Reserve Requirement constraint Shadow Price.

For each Dispatch Interval, the Transmission Provider shall use the SCED-Pricing algorithm to establish Real-Time Ex Post LMPs and Real-Time Ex Post MCPs. The Real-Time Ex Post LMPs and Real-Time Ex Post MCPs will be subject to input data validation and adherence to the price calculation requirements. Input data validation corrections will be made pursuant to Section 40.2.18 of this Tariff. The Real-Time Ex Post LMPs and Real-Time Ex Post MCPs are used to settle Real-Time Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve deviations and are determined as described below:

a. Determination of the Real-Time Ex Post LMPs at Elemental Pricing Nodes

The Transmission Provider shall calculate Real-Time Ex Post LMPs for each Dispatch Interval and Elemental Pricing Node in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post LMP at an Elemental Pricing Node in a specific Dispatch Interval is the marginal Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve and, if applicable, Reserve Scarcity costs, Up Ramp Capability scarcity costs, Down Ramp Capability scarcity costs, and/or Short-Term Reserve scarcity costs to supply Energy to Load at the Elemental Pricing Node during the Dispatch Interval using the SCED-Pricing algorithm, described in Schedule 29A. The Real-Time Ex Post LMPs are established based on (i) Generation Offers, (ii) Demand Response Resource Offers, (iii) External Asynchronous Resource Offers, (iv) Emergency Demand Response resource Offers; (v) Electric Storage Resource Offers; and (vi) Proxy Offers when appropriate as specified in Schedule 29A.

i. Calculation of Marginal Congestion Component. The Transmission Provider will calculate the Cost of Congestion at each Elemental Pricing Node as a component of the Real-Time Ex Post LMP (the Marginal Congestion Component). The Marginal Congestion Component of a Real-Time Ex Post LMP reflects the marginal cost of managing the transmission congestion and enforcing Sub-Regional Power Balance Constraints that will arise from an incremental Energy demand at the Elemental Pricing Node supplied by an incremental Energy injection at the Reference Bus.

ii. Calculation of Marginal Losses Component. The Transmission Provider will calculate the Cost of Losses at each Elemental Pricing Node as a component of the Real-Time Ex Post LMP at that Elemental Pricing Node (the Marginal Losses Component). The Marginal Losses Component of any Real-Time Ex Post LMP reflects the marginal cost of serving System Losses that arise from an incremental Energy demand at the Elemental Pricing Node supplied by a loss adjusted Energy Injection at the Reference Bus.

b. Determination of Real-Time Ex Post LMPs at Aggregate Price Nodes.

The Transmission Provider shall calculate Real-Time Ex Post LMPs for each Dispatch Interval and Aggregate Price Node in the Real-Time Energy and Operating Reserve Market. The calculation of Real-Time Ex Post LMPs for Aggregate Price Nodes will be based on established normalized weighting factors for each Elemental Pricing Node defined in the Aggregate Price Node. The Aggregate Price Node is equal to the sum of the products of the Real-Time Ex Post LMP at each Elemental Pricing Node and the associated weighting factor for the Elemental Pricing Node.

c. Determination of the Real-Time Ex Post LMPs at Commercial Pricing Nodes

The Transmission Provider shall establish Real-Time Ex Post LMPs for each Dispatch Interval and Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market. The Real-Time Ex Post LMPs for Commercial Pricing Nodes, including the Marginal Congestion Component and Marginal Losses Component, shall be set equal to the Real-Time Ex Post LMP at the Elemental Pricing Node or Aggregate Price Node on which the Commercial Pricing Node is based.

d. Determination of the Real-Time Ex Post LMP at a Resource Commercial Pricing Node.

The Transmission Provider shall determine the Real-Time Ex Post LMP at a Resource Commercial Pricing Node as follows:

i. If the Resource has a single injection and/or withdrawal point, the Real-Time Ex Post LMP for the Resource Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Elemental Pricing Node representing the Bus connected to the single injection and/or withdrawal point of the Resource.

ii. If the Resource has multiple injection points, that may or may not be connected to different Buses, the Real-Time Ex Post LMP for the Resource Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Buses connected to each of the injection points of the Resource.

The Aggregate Price Node weighing factors are specified by the Market Participant when the asset is registered.

e. Determination of the Real-Time Ex Post LMP at a Load Zone Commercial Pricing Node

The Transmission Provider shall determine an Real-Time Ex Post LMP for the Load Zone Commercial Pricing Node as follows:

i. If the Load Zone consists of a single Load, the Real-Time Ex Post LMP for the Load Zone Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Elemental Pricing Node representing the Bus connected to the single Load.

ii. If the Load Zone consists of multiple Loads, the Real-Time Ex Post LMP for the Load Zone Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Load Zone. The Aggregate Price Node representing the Load Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the Load Zone are connected. The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the Load Zone's demand at the Elemental Pricing Node to the total demand of the Load Zone as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operation Day.

f. Determination of the Real-Time Ex Post LMP at a Hub Commercial Pricing Node

The Transmission Provider shall determine Real-Time Ex Post LMP for a Hub Commercial Pricing Node as follows:

i. If the Hub consists of a single Elemental Pricing Node, the Real-Time Ex Post LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Elemental Pricing Node.

ii. If the Hub consists of multiple Elemental Pricing Nodes, the Real-Time Ex Post LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Hub. The weighting factor for a specific Elemental Pricing Node is equal to a fixed normalized value determined by the Transmission Provider for the Hub, except as provided below for an ARR Zone administered as a Hub Commercial Pricing Node.

iii. Where an ARR Zone is administered as a Hub Commercial Pricing Node consisting of multiple Elemental Pricing Nodes, the Real-Time Ex Post LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Hub. The Aggregate Price Node representing the ARR Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the ARR Zone are connected.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the ARR Zone's demand at the Elemental Pricing Node to the total demand of the ARR Zone, as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operating Day.

g. Determination of the Real-Time Ex Post LMP at an Interface Commercial Pricing Node

The Transmission Provider shall determine Real-Time Ex Post LMP for an Interface Commercial Pricing Node as follows:

i. If the Interface consists of a single external Elemental Pricing Node, the Real-Time Ex Post LMP for the Interface Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Elemental Pricing Node.

ii. If the Interface consists of multiple external Elemental Pricing Nodes, the Real-Time Ex Post LMP for the Interface Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Interface. The weighting factor for a specific Elemental Pricing Node is equal to a normalized value determined by the Transmission Provider for the Interface.

h. Determining the Real-Time Ex Post Regulating Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post MCPs for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources is equal to the sum of the (i) Market-

Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Regulating Reserve Constraint Shadow Price, (iv) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (v) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Regulating Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

i. Determining the Real-Time Ex Post Spinning Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post MCPs for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (iv) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning

Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost for managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

j. Determining the Real-Time Ex Post Spinning Reserve Market Clearing Prices for Demand Response Resources- Type I

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post MCPs for Spinning Reserve for Demand Response Resources – Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market if such Demand Response Resources – Type I are eligible to provide Spinning Reserve as determined by Applicable Reliability Standards. The Real-Time Ex Post MCP for Spinning Reserve for Demand Response Resources –Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market- Wide Regulating and Spinning Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

k. Determining the Real-Time Ex Post Supplemental Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

The Transmission Provider shall calculate the Real-Time Ex Post MCPs for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, or External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, if applicable, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

l. Determining the Real-Time Ex Post Supplemental Reserve Market Clearing Prices for Demand Response Resources - Type I

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post MCPs for Supplemental Reserve for Demand Response Resources - Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Supplemental Reserve for Demand Response Resources - Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, and (ii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

m. Determining the Real-Time Ex Post Up Ramp Capability Market Clearing Prices

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post Up Ramp Capability MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED-Pricing algorithm. The Real-Time Ex Post Up Ramp Capability MCP for a Resource is the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Constraint is as set forth in Schedule 29A.

n. Determining the Real-Time Ex Post Down Ramp Capability Market Clearing Prices

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post Down Ramp Capability MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED-Pricing algorithm. The Real-Time Ex Post Down Ramp Capability MCP for a Resource is the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Constraint is as set forth in Schedule 29A.

o. Real-Time Ex Post LMP and Real-Time Ex Post MCP Price Cap. All Real-Time Ex Post LMPs and Real-Time Ex Post MCPs will be capped at the Pricing VOLL.

p. Determining the Ex Post Regulating Mileage Market Clearing Price

The Transmission Provider shall calculate the Ex Post Regulating Mileage MCPs for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market. The Ex Post Regulating Mileage MCP is the highest Regulating Mileage Offer among all Resources that meet the following criteria: (1) if the Resource has a Day-Ahead Schedule for cleared Regulating Reserve, then the Regulating Reserve Dispatch Status in the Day-Ahead Energy and Operating Reserve Market must be economic, (2) the Regulating Reserve Dispatch Status has to be economic in the Real-Time Energy and Operating Reserve Market, and (3) the Resource has a non-zero Dispatch Target for Regulating Reserve in that Dispatch Interval. The Ex Post Regulating Mileage MCP is used to settle Additional Regulating Mileage in that Dispatch Interval.

q. Determining the Real-Time Ex Post Short-Term Reserve Market Clearing Prices

On a real-time market basis, the Transmission Provider shall calculate the real-time Ex Post Short-Term reserve MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED-Pricing algorithm. The real-time Ex Post Short-Term Reserve MCP for a Resource is the applicable Co-optimized Zonal Short-Term Reserve Requirement constraint Shadow Price.

Capacity Shortage Conditions in the Real-Time Energy and Operating Reserve Market: The Transmission Provider shall take the measures set forth below during Capacity shortage conditions to maintain reliability within the MISO Balancing Authority Area.

a. RAC

If during any RAC process, the Transmission Provider's forecast of Real-Time demand and Operating Reserve Requirements, either on a MISO Balancing Authority Area basis or Sub-Area basis, cannot be satisfied by committing all available non-Emergency Capacity, up to Hourly Economic Maximum Limits, up to the Hourly Economic Maximum Discharge Limits and Hourly Minimum Energy Storage Levels for Electric Storage Resources, and the Forecast Maximum Limit for Dispatchable Intermittent Resources, the Transmission Provider shall implement the following procedures:

i. Step One. The Transmission Provider shall: incorporate for use in the RAC commitment process, the order of which is specified in the Transmission Provider's Emergency operating procedures: (i) the Market Participants' Offers submitted for each Generation Resource, Demand Response Resource - Type II, External Asynchronous Resource, and Hourly Emergency Minimum Energy Storage Level or Hourly Emergency Maximum Discharge Limit for an Electric Storage Resource, or the Forecast Maximum Limit for Dispatchable Intermittent Resources, except for Resources selected to provide Regulating Reserve, (ii) the commitment of Generation Resources, Demand Response Resources - Type I, and Demand Response Resources - Type II that are designated as available for Emergency conditions only, and the commitment of Electric Storage Resources with a Commitment Status of Emergency Discharge, (iii) the curtailment of Export Schedules, in amounts required to relieve the shortage condition in an economic manner; and (iv) the schedules of External Resources that qualified as Planning Resources.

ii. Step Two. If the action under Step One above is not sufficient to relieve the anticipated shortage condition, the Transmission Provider shall declare an EEA--Level 1. In the event that a significant shortage of Operating Reserve is anticipated, the Transmission Provider shall declare an EEA--Level 2 and shall mitigate, but not necessarily eliminate, the Operating Reserve deficiency through use of the following options, the order of which is specified in the Transmission Provider's Emergency operating procedures: (a) Issuing EDR Dispatch Instructions to EDR Participants based upon EDR Offers submitted (b) initiating Emergency Energy purchases in accordance with the procedures set forth in Section 40.2.22, (c) issuing public appeals to reduce demand as appropriate, (d) directing Local Balancing Authorities to implement voltage reductions, and (e) directing Load Serving Entities to curtail appropriate amounts of Load Modifying Resources.

b. Real-Time Dispatch Interval

During any SCED Dispatch Interval for which the Transmission Provider has previously issued an EEA--Level 1 or EEA--Level 2, the Transmission Provider shall implement the following procedures to clear the Real-Time Energy and Operating Reserve Market:

i. For those Resources selected to operate above the Hourly Economic Maximum Limits and Hourly Economic Maximum Discharge Limits and down to the Hourly Minimum Energy Storage Level during the RAC process pursuant to Section 40.2.20.a.i., the Transmission Provider shall use the Market Participant's Offers for such Resources up to the Hourly Emergency Maximum Limit and Hourly Emergency Maximum Discharge Limit and down to the Hourly Minimum Energy Storage Level in the SCED to calculate Real-Time Ex Ante LMPs and Real-Time Ex Ante MCPs, and shall use the Resource's Proxy Offers specified in Schedule 29A in the SCED-Pricing to calculate Real-Time Ex Post LMPs and Real-Time Ex Post MCPs which will reflect Scarcity Pricing based upon Demand Curves, if sufficient Operating Reserve is not cleared to meet the Market-Wide Operating Reserve Requirement, if sufficient Up Ramp Capability is not cleared to meet the Market-Wide Up Ramp Capability Requirement, and/or if sufficient Short-Term Reserve is not cleared to meet the Market-Wide Short-Term Reserve Requirement. For scheduled External Resources that qualified as Planning Resources, the Transmission Provider shall also use their Proxy Offers specified in Schedule 29A in the SCED-Pricing to calculate Real-Time Ex Post LMPs and Real-Time Ex Post MCPs.

ii. For Load Modifying Resources, Emergency Demand Response resources and Emergency Energy Purchases selected to operate during the RAC process pursuant to Section 40.2.20.a.ii, the Transmission Provider shall use their Proxy

Offers specified in Schedule 29A in the SCED-Pricing to calculate Real-Time Ex Post LMPs and Real-Time Ex Post MCPs

iii. If as a result of the Transmission Provider actions pursuant to Section 40.2.20.b.i, Energy balance cannot be achieved, the Transmission Provider shall declare an EEA-Level 3 and may implement Load Shedding pursuant to the Transmission Provider's Emergency operating procedures. Load Shedding will be implemented on a MISO Balancing Authority Area basis, or a on a Sub-Area basis if limited by transmission constraints or Sub-regional Power Balance Constraints, as required to restore Energy balance. The Load Shedding obligation of each Load Serving Entity shall be implemented through instructions to the affected Local Balancing Authorities as set forth in the protocols of the Balancing Authority Agreement. Load Shedding shall be allocated to each affected Local Balancing Authority on a pro rata, Load Ratio Share basis, determined by the ratio of the total amount of Load Shedding required to achieve Energy balance to the amount of the real-time load remaining, or if the Load Shedding is to occur in the next hour, to the projected load for the next-hour, for the Sub-Area or the entire MISO Balancing Authority Area, as applicable. During Emergency conditions where Load Shedding is instructed by the Transmission Provider when the affected area is the MISO Balancing Authority Area or Sub-Area, Real-Time Ex Ante LMPs, Real-Time Ex Ante MCPs, Real-Time Ex Post LMPs and Real-Time Ex Post Operating Reserve MCPs will be set to the Pricing VOLL, either on a MISO

Balancing Authority Area basis or Sub-Area basis, as applicable, until the Emergency condition is no longer in effect.

iv. When an EEA-Level 3 declared by the Transmission Provider pursuant to Section 40.2.20.b.iii satisfies any of the following conditions, the Pricing VOLL shall be adjusted as follows:

(1) Once the cumulative duration of the EEA-Level 3 reaches four (4) hours, the Real-Time Energy and Operating Reserve Market Pricing VOLL as set forth in Sections 40.2.15.p and 40.2.17.o shall be reduced to $5,000/MWh. The cumulative EEA-Level 3 duration is paused when the EEA-Level 3 is exited, but Capacity shortage conditions remain, as declared by the Transmission Provider. The cumulative EEA-Level 3 duration is deemed ended when the Transmission Provider declares an end to Capacity shortage conditions.

(2) If at the time of the close of the Day-Ahead Energy and Operating Reserve Market, the Capacity shortage that led to the declaration of the EEA-Level 3 is continuing, the Pricing VOLL shall be reduced to $5,000/MWh. This Pricing VOLL is applied on the next Operating Day for both the Day-Ahead Energy and Operating Reserve Market (Sections 39.2.9.p and 39.2.10.b) and the Real-Time Energy and Operating Reserve Market (Sections 40.2.15.p and 40.2.17.o).

(3) If the Capacity shortage conditions described in sub-paragraph (2) persist at the time of the close of any additional Day-Ahead Energy and

Operating Reserve Market(s), the Pricing VOLL shall be further reduced to $2,000/MWh for both the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market for the next Operating Day(s).

(4) After conditions described in sub-paragraphs (1), (2) and/or (3) have ended and the Transmission Provider declares an end to Capacity shortage conditions, the Pricing VOLL shall be reset to the initial value of $10,000/MWh, depending on applicable conditions in sub-parts a and b below:

a. At the end of the current Operating Day, if the Transmission Provider declares an end to the Capacity shortage conditions before the close of the Day-Ahead Energy and Operating Reserve Market.

b. At the end of the next Operating Day, if the Transmission Provider declares an end to the Capacity shortage conditions after the close of the Day-Ahead Energy and Operating Reserve Market.

c. Notice

The Transmission Provider shall post on its public website notice of the existence and duration of the conditions requiring the implementation of the procedures set forth in this Section 40.2.20.

SCHEDULE 28

Demand Curves for Operating Reserve, Regulating and Spinning Reserve, and Regulating Reserve, Up Ramp Capability, Down Ramp Capability, and Market-Wide Short-Term Reserve

I. INTRODUCTION

Demand Curves shall be used by the Transmission Provider to determine the incremental value of Market-Wide Operating Reserve, Market-Wide Regulating and Spinning Reserve, Market-Wide Regulating Reserve, Market-Wide Up Ramp Capability, Market-Wide Down Ramp Capability, and Market-Wide Short-Term Reserve to Load Serving Entities and, if applicable, Market Participants with Exports. Demand Curves shall be used in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets.

II. GENERAL

The Reserve Demand Curves shall be developed to price Operating Reserve when sufficient Operating Reserves, Regulating and Spinning Reserves, or sufficient Regulating Reserves are not cleared to meet the corresponding Operating Reserve, Regulating and Spinning Reserve, or Regulating Reserve requirement. The Up Ramp Capability Demand Curve shall be developed to price Up Ramp Capability when sufficient Up Ramp Capability is not cleared to meet the Market-Wide Up Ramp Capability Requirement. The Down Ramp Capability Demand Curve shall be developed to price Down Ramp Capability when sufficient Down Ramp Capability is not cleared to meet the Market-Wide Down Ramp Capability Requirement. The Market-Wide Short-Term Reserve Demand Curve shall be developed to price Short-Term Reserve when sufficient Short-Term Reserve is not cleared to meet the Market-Wide Short-Term Reserve Requirement.

III. MARKET-WIDE OPERATING RESERVE DEMAND CURVE

When the cleared Operating Reserve level is less than the Market-Wide Operating Reserve Requirement, the Operating Reserve price is determined using a Market-Wide Operating Reserve Demand Curve. The price is related to the amount of Operating Reserve cleared relative to the Operating Reserve Requirement, determined as follows:

i. If less than 4% of the requirement level has cleared, the price is VOLL less the maximum Market-Wide Regulating Reserve Demand Curve Price for the month.

ii.i. If the cleared level of Operating Reserve is less than a the minimum of (100%, or the percentage amount required to satisfy the Most Severe Single Contingency, as defined by NERC, and as determined by the Reserve Sharing Group, times the Operating Reserve Requirement), but more than or equal to 4% of the requirement level has cleared, the price is the product of (i) the Value of Lost Load ("VOLL")System VOLL and (ii) the estimated conditional probability of a loss of load based on the occurrence of a single forced Resource outage of 100 MW or greater at the cleared Market-Wide Operating Reserve level – as further described in the Transmission Provider's Business Practices ManualsLoss of Load Probability Curve. This price has maximum and minimum limits. The maximum price is VOLL less the maximum Market-Wide Regulating Reserve Demand Curve Price level for the month$6,000/MWh. The minimum price is the sum of the Energy Offer Hard Price Cap and the Contingency Reserve Offer Price Cap$1,100/MWh (sum of the lower bound of the Emergency Tier II Offer Floor, $1,000 and the Contingency Reserve Offer Price Cap, $100).

iii.ii. If the cleared level of Operating Reserve is less than 100% of the requirement level has cleared, and the cleared amount isOperating Reserve Requirement, but greater than or equal to the percentage amount required to satisfy the Most Severe Single Contingency, as defined by NERC, and as determined by the Reserve Sharing Group, the price is the sum of the Energy Offer Soft Price Cap and the Contingency Reserve Offer Price Cap$600/MWh (sum of the lower bound of the Emergency Tier I Offer Floor, $500 and the Contingency Reserve Offer Cap, $100). This provision will not apply when the percentage amount required to satisfy the Most Severe Single Contingency, as defined by NERC, and as determined by the Reserve Sharing Group is greater than or equal to 100% of the requirement level.

iv. The VOLL shall be equal to $3,500 per MWh.

IV. MARKET-WIDE REGULATING RESERVE DEMAND CURVE

Availability of Regulating Reserves depends both upon the Resources that are committed and on how the committed Resources are dispatched. When the Transmission Provider is not able to meet the Market Wide Regulating Reserve Requirement using committed Resources, it can take actions such as changing the commitment of Resources to make Capacity available to meet Regulating Reserve Requirements. For cleared Market-Wide Regulating Reserve levels less than the Market-Wide Regulating Reserve Requirement, the Market-Wide Regulating Reserve Demand Curve price will be set based upon the greater of (i) the Contingency Reserve Offer Cap or (ii) the average cost per MWh of committing and running a peaking unit for an hour.

The Market-Wide Regulating Reserve Demand Curve price shall be established monthly and posted on the Transmission Provider's website seven (7) days prior to the beginning of the month for which it will be effective. The average cost per MWh of committing and running a peaking unit for an hour shall be calculated based upon:

(a) A spot gas price index in $/MMBtu, which will be specified, and amended when necessary, in the Transmission Provider's Business Practices Manuals or other documentation on the Transmission Provider's website. Prior to each month, the average of the spot gas price index over the first three weeks of the month prior to the month for which the Market-Wide Regulating Reserve Demand Curve price is being calculated will be calculated.

(b) An annual proxy heat rate determined once a year by the Transmission Provider as the mean of the single hour Offer prices of peakers offered in the Day Ahead and Real-Time Markets over the past year, as specified in (c) through (f) below. The product of the monthly average spot gas price from (a) and the annual proxy heat rate from (b) will be the Market Wide Regulating Reserve Demand Curve Price for each Hour for cleared Market Wide Regulating Reserve levels less than the Market Wide Regulating Reserve Requirement.

(c) AnnualProxyHeatRate is an effective heat rate based on the peaker Offers submitted each day and the spot gas prices for that day for each of the days in the year (to the date of calculation). This value will be expressed as MMBtu/MWh and will be calculated annually as follows:

Annual Proxy Heat Rate = $\left(\sum \sum \text{Average Daily Proxy Heat Rate}_{o,d} \right)$

$$\frac{\sum_{o}\sum_{d}}{\text{Offer Count}}$$

where:

"o" is an index of the Day-Ahead and Real-Time Market peaker Offers in a day;

"d" is an index of the days in the year to the date of calculation, and

"Offer Count" is the total number of Offers by peakers in the Day-Ahead and Real-Time Markets over the year to the date of calculation.

The average daily proxy heat rate for each Offer o on each day d, $AverageDailyProxyHeatRate_{o,d}$, will be calculated as

$$\frac{\sum_{h} (\text{AIE Cost}_{o, d, h} + \text{ASU Cost}_{o, d, h} + \text{ANL Cost}_{o, d, h})}{\text{Number Hours} \times \text{Spot Gas Price}_{d}}$$

where:

"d" indexes the day;

"h" indexes the hours of the day d;

"NumberHours" is the number of hours for Offer o on day d;

$SpotGasPrice_d$ is the spot gas price on day d as given in the index specified in (a);

$AIECost_{o,d,h}$ is the average Incremental Energy Price in $/MWh for Offer o on day d in Hour h as defined in (d) below;

$ASUCost_{o,d,h}$ is the average start-up cost in $/MWh for Offer o on day d in Hour h as defined in (e) below; and

$ANLCost_{o,d,h}$ is the average no-load cost in \$/MWh for Offer o on day d in Hour h as defined in (f) below.

(d) $AIECost_{o,d,h}$ is defined as

$$\frac{\int_{0}^{EconMax_{o,d,h}} IEOffer\,Curve_{o,d,h}(x)dx}{EconMax_{o,d,h}}$$

where:

$IEOfferCurve_{o,d,h}(x)$ is the Incremental Energy Price curve in Offer o on day d in Hour h;

$EcoMax_{o,d,h}$ is the economic maximum output for Offer o on day d in Hour h.

(e) $ASUCost_{o,d,h}$ is defined as

$$\frac{SUOffer_{o,d,h}}{EconMax_{o,d,h}}$$

where:

$SUOffer_{o,d,h}$ is the cold Start-Up Offer price in Offer o on day d in Hour h.

(f) $ANLCost_{o,d,h}$ is defined as

$$\frac{NLOffer_{o,d,h}}{EconMax_{o,d,h}}$$

where:

$NLOffer_{o,d,h}$ is the No-Load Offer price in Offer o on day d in Hour h.

V. MARKET-WIDE REGULATING AND SPINNING RESERVE DEMAND CURVE

For each cleared Regulating and Spinning Reserve level less than the Market-Wide Regulating and Spinning Reserve Requirement, the Market-Wide Regulating and Spinning Reserve Demand Curve shall be used to set the Market-Wide Regulating and Spinning Reserve constraint Shadow Price. The Regulating and Spinning Reserve Demand Curve is established based on the level of Regulating and Spinning Reserve shortages. As the Regulating and Spinning Reserve shortage increases, the corresponding Regulating and Spinning Reserve Demand Curve value increases as well.

For cleared Market- Wide Regulating and Spinning Reserve levels greater than ninety percent (90%) but less than one hundred percent (100%) of the Market-Wide Regulating and Spinning Reserve Requirement, the Market- Wide Regulating and Spinning Reserve will be priced at $65 per MWh. For cleared Market-Wide Regulating and Spinning Reserve levels less than ninety percent (90%) of the Market-Wide Regulating and Spinning Reserve Requirement, the Market- Wide Regulating and Spinning Reserve will be priced at $98 per MWh.

VI. MARKET-WIDE UP RAMP CAPABILITY DEMAND CURVE

When the cleared Up Ramp Capability level is less than the Market-Wide Up Ramp Capability Requirement, the Up Ramp Capability price is determined using a Market-Wide Up Ramp Capability Demand Curve. The price is related to the amount of Up Ramp Capability cleared relative to the Market-Wide Up Ramp Capability Requirement, determined as follows:

i. If less than 9% of the requirement level has cleared, the price is $31/MWh.

ii. If less than 13% of the requirement level has cleared, but more than or equal to 9% of the requirement level has cleared, the price is $29/MWh.

iii. If less than 18% of the requirement level has cleared, but more than or equal to 13% of the requirement level has cleared, the price is $27/MWh.

iv. If less than 21% of the requirement level has cleared, but more than or equal to 18% of the requirement level has cleared, the price is $25/MWh.

v. If less than 26% of the requirement level has cleared, but more than or equal to 21% of the requirement level has cleared, the price is $23/MWh.

vi. If less than 37% of the requirement level has cleared, but more than or equal to 26% of the requirement level has cleared, the price is $18/MWh.

vii. If less than 47% of the requirement level has cleared, but more than or equal to 37% of the requirement level has cleared, the price is $14/MWh.

viii. If less than 53% of the requirement level has cleared, but more than or equal to 47% of the requirement level has cleared, the price is $12/MWh.

ix. If less than 100% of the requirement level has cleared, but more than or equal to 53% of the requirement level has cleared, the price is $5/MWh.

x. If more than or equal to 100% of the requirement level has cleared, the price is $0/MWh.

xi. The Market-Wide Up Ramp Capability Demand Curve price will be determined by the Transmission Provider to balance tradeoffs between increased costs of the additional system flexibility and the operational savings. Because Up Ramp Capability provides capacity that can be converted to Energy in a future Dispatch Interval in response to uncertain events, the Transmission Provider approach for determining the Market-Wide Up Ramp Capability Demand Curve price shall include the variability of the market-wide forecasted changes in load and Scheduled Interchange while considering the contribution of non-dispatchable generation served by the dispatchable system resources. It is not required that the Market-Wide Up Ramp Capability Demand Curve price attempts to ensure that Up Ramp Capability levels will cover all potential events.

VII. MARKET-WIDE DOWN RAMP CAPABILITY DEMAND CURVE

When the cleared Down Ramp Capability level is less than the Market-Wide Down Ramp Capability Requirement, the Down Ramp Capability price is determined using a Market-Wide Down Ramp Capability Demand Curve. The price is related to the amount of Down Ramp Capability cleared relative to the Market-Wide Down Ramp Capability Requirement, determined as follows:

i. A single demand curve price is used for all levels of cleared Down Ramp Capability.

The Market-Wide Down Ramp Capability Demand Curve price will be determined by the Transmission Provider to balance tradeoffs between increased costs of the additional system flexibility and the operational savings. Because Down Ramp Capability provides capacity that can be converted to Energy in a future Dispatch Interval in response to uncertain events, the Transmission Provider approach for determining the Market-Wide Down Ramp Capability Demand Curve price shall include the variability of the market-wide forecasted changes in load and Scheduled Interchange while considering the contribution of non-dispatchable generation served by the dispatchable system resources.

It is not required that the Market-Wide Down Ramp Capability Demand Curve price attempts to ensure that Down Ramp Capability levels will cover all potential events. The Market-Wide Down Ramp Capability Demand Curve price will be set to $0/MWh, to disable the product after the removal of Dispatchable Intermittent Resource eligibility.

VIII. MARKET-WIDE SHORT-TERM RESERVE DEMAND CURVE

When the cleared Short-Term Reserve level is less than the Market-Wide Short-Term Reserve Requirement, the Market-Wide Short-Term Reserve Demand Curve shall be used to set the Market-Wide Short-Term Reserve constraint Shadow Price. The price is determined as follows:

i. If less than 2500 MW of the requirement level has cleared, the price is $500/MWh.

ii. If less than 2600 MW of the requirement level has cleared, but more than or equal to 2500 MW of the requirement level has cleared, the price is $478/MWh.

iii. If less than 2800 MW of the requirement level has cleared, but more than or equal to 2600 MW of the requirement level has cleared, the price is $434/MWh.

iv. If less than 2900 MW of the requirement level has cleared, but more than or equal to 2800 MW of the requirement level has cleared, the price is $394/MWh.

v. If less than 3000 MW of the requirement level has cleared, but more than or equal to 2900 MW of the requirement level has cleared, the price is $393/MWh.

vi. If less than the Market-Wide Short-Term Reserve Requirement has cleared, but more than or equal to 3000 MW of the requirement level has cleared, the price is $100/MWh.

vii. If more than or equal to the Market-Wide Short-Term Reserve Requirement has cleared, the price is $0/MWh. The Market-Wide Short-Term Reserve Requirement shall be no less than 3000 MW.

viii. The Market-Wide Short-Term Reserve Demand Curve price will be determined by the Transmission Provider to balance tradeoffs between increased costs of the additional system flexibility and the operational savings. The determination of the Market-Wide Short-Term Reserve Demand Curve price is not required to ensure that Short-Term Reserve levels will cover all potential events.

SCHEDULE 30

EMERGENCY DEMAND RESPONSE INITIATIVE

I. GENERAL

Schedule 30 provides for the commitment and dispatch of interruptible demand, behind-the-meter generation and other demand resources that are capable of helping meet the energy balance during NERC Energy Emergency Alert 2 ("EEA2"), Alert 3 ("EEA3"), or any other types of Emergency events. Schedule 30 provides procedures for the Transmission Provider to be able to dispatch such resources ("Emergency Demand Response" or "EDR") during Emergency events. References, within Schedule 30, to Emergency events include both Transmission System and capacity Emergencies. Such procedures provide for reductions in Load and/or increased behind-the-meter generation (*i.e*., "demand reduction") to be compensated under the conditions specified below (*i.e*., "EDR Initiative"). These EDR procedures: (i) enhance the Transmission Provider's ability to utilize demand response during Emergency events; (ii) enable the Transmission Provider to establish curtailment priorities; (iii) reflect varying costs of EDR options; and (iv) allow the Transmission Provider to evaluate and dispatch EDR Offers in merit order by location and by priority status.

II. EMERGENCY DEMAND RESPONSE PARTICIPATION

A Market Participant within the Transmission Provider Region may become an EDR Participant by complying with these Schedule 30 requirements if it: (i) has the ability to cause a reduction in demand in response to receiving an EDR Dispatch Instruction from the Transmission Provider either because the Market Participant is the operator of a facility capable of reducing demand, or the Market Participant is a Load Serving Entity ("LSE") or ARC with a contract that entitles the Market Participant to reduce Load at such facility; or (ii) has the ability to cause an increase in output from a behind-the-meter-generation resource to enable a net demand reduction, in response to receiving an EDR Dispatch Instruction from the Transmission Provider. Only a Market Participant is allowed to register to become an EDR Participant on behalf of an asset owner and be an eligible EDR Participant by submitting EDR Offers to the Transmission Provider to reduce demand during an Emergency event.

EDR Participants must be able to receive an EDR Dispatch Instruction from the Transmission Provider via XML. EDR Participants must utilize metering equipment that meets the requirements, including, but not limited to, the ability to provide integrated hourly kWh values on a Commercial Price Node ("CPNode") basis. EDR Participants may provide hourly kWh values for non-interval Metered demand reductions (*e.g.*, direct Load control) using the alternative Measurements and Verification procedures provided in Attachment TT. Measurement of demand reductions shall be made on an EDR resource basis, aggregated across assets that define the EDR resource, to enable the EDR Participant's demand reduction to be identified with an LMP; EDR Offers can set the Real-Time Ex Post LMP.

If the behind-the-meter-generation resource designated by an EDR Participant historically is operated during non-Emergency conditions, the Energy that can be offered under the EDR Initiative is the increase in output from a behind-the-meter-generation resource to enable a net Demand reduction, in response to receiving an EDR Dispatch Instruction from the Transmission Provider. Determination of such output shall be based on the EDR Offer and the amount of load reduction provided, consistent with Section VII below or Attachment TT. If a Demand reduction is subject to a contractual agreement with an LSE, then the operator of the facility will be entitled to submit an EDR Offer for the specified Demand reduction to the Transmission Provider only if, and to the extent that, an EDR Offer is consistent with the terms and conditions of the contract with such LSE and the operator of the facility is a Market Participant.

EDR Participants shall be required to identify in their EDR Offers if the Demand reduction can be variable or alternatively provide a specific level of Demand reduction. Upon receipt of an EDR Dispatch Instruction, an EDR Participant shall either: 1) curtail to the firm service level specified in their EDR Offer; or 2) provide a specific level of Demand reduction as specified in their EDR Offer. EDR Participants electing the first option shall be required to identify an expected peak Load in their EDR Offer, updated daily as required to reflect the amount of Demand reduction achievable.

EDR Participants are responsible for maintaining Demand reduction information, including the amount in MWh of reduced Demand during all types of Emergency events whenever the EDR Participant receives an EDR Dispatch Instruction from the Transmission Provider.

III. EMERGENCY DEMAND RESPONSE REGISTRATION

Prior to participating in the EDR Initiative, a Market Participant must complete the EDR registration form as specified in the BPM for Market Registration and submit it to the Transmission Provider. An EDR Participant and its associated Load asset or behind-the-meter generation asset must be defined in the EDR registration form. EDR Participants that are ARCs must meet all the ARC-specific requirements in Section 38.6.

At the time of EDR registration, an EDR Participant shall provide complete details regarding any limitations on the EDR Participant's ability to reduce Demand, including, but not limited to: (i) information regarding the total number of times that the EDR Participant is able to reduce Demand during the year; (ii) the number of times that the EDR Participant has already reduced Demand during the current year; and (iii) any and all restrictions (including, but not limited to, contractual restrictions) that may preclude the EDR Participant from reducing Demand in the future. These limitations provided at the time of registration but not included in the EDR Offer will have no impact on the Transmission Provider's decision to commit the EDR. It is the responsibility of the EDR Participant to ensure the limitations that exist outside of the parameters outlined in the EDR Offer are not violated.

An EDR Participant that intends to use a behind-the-meter generation resource for the purpose of reducing demand during an Emergency event shall confirm to the Transmission Provider in writing that: (1) it holds all necessary permits (including, but not limited to, environmental permits) applicable to the operation of the behind-the-meter generation resource; (2) it possesses rights to operate the behind-the-meter generation resource that are equivalent to ownership of such unit; and (3) the behind-the-meter generation resource is not a designated Network Resource. Unless notified otherwise, the Transmission Provider shall deem such representation applies each time the behind-the-meter generation resource is used to reduce demand during an Emergency event and that the behind-the-meter generation resource is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits. The EDR Participant shall be solely liable for identification of and compliance with all such applicable permits.

The Transmission Provider shall notify the Market Participant when it has met all required qualifications to become an eligible EDR Participant and that the Market Participant is eligible to submit EDR Offers.

IV EDR OFFER

An EDR Participant seeking to reduce Demand during an Emergency event and receive compensation under this Schedule 30 must submit an EDR Offer to reduce Load to the Transmission Provider no later than 1030 EPT on the day prior to the next Operating Day and will be in effect for the next Operating Day. If an EDR Participant is unable to reduce Demand in accordance with an EDR Offer due to exigent circumstances, then the EDR Participant shall promptly notify the Transmission Provider in accordance with the procedures in the Business Practices Manuals. Such notification must be made prior to the issuance of EDR Dispatch Instructions.

The EDR Offer shall specify: (i) the minimum and maximum amount of the offered Demand reduction (in minimum increments of 0.1 MWh) or; specify the firm service level to which the EDR Participant will curtail Demand and specify the EDR Participant's expected peak Load; (ii) the applicable minimum and maximum number of contiguous Hours for which the Demand reduction must be committed for such curtailments; (iii) shutdown costs associated with a demand reduction, including direct labor and equipment costs and/or opportunity costs; (iv) the number of Hours of advance notice from the Transmission Provider that the EDR Participant requires to reduce Demand; (v) the daily availability of the Demand reduction; (vi) an hourly curtailment offer for such Demand reduction specified in dollars per MWh, not to exceed ~~VOLL~~$3,500/MWh. The hourly curtailment offer is a single dollar per MWh value that is applicable to every Hour of the day. Any EDR Offer shall remain valid until it is modified or revoked by the EDR Participant. EDR Offers must be made for a minimum period of one (1) Operating Day and may not be modified after 1030 EPT on the day prior to the next Operating Day. EDR Offers must be consistent with any applicable contractual agreements with an LSE.

V. ISSUANCE OF EMERGENCY DEMAND RESPONSE DISPATCH INSTRUCTIONS

The Transmission Provider may issue EDR Dispatch Instructions to EDR Participants, based upon factors, including, but not limited to, consideration of: (i) terms and conditions of the EDR Offer; (ii) anticipated need for Demand reduction during Emergency events; (iii) availability of other EDR Demand reductions; (iv) the location of the Demand reduction; and (v) anticipated future Emergency conditions. EDR Dispatch Instructions shall detail: (i) the commencement of such Demand reductions; (ii) the amount of Demand reduction that the EDR Participant shall reduce, including a schedule for modified Demand reductions, if appropriate; and (iii) the duration for such Demand reductions. The Transmission Provider may also issue updates to EDR Dispatch Instructions if changing system conditions warrant such action. Any updates to EDR Dispatch Instructions will be consistent with the EDR Offer. The Transmission Provider's Emergency operating procedures documentation shall provide further detailed information on EDR Dispatch Instructions during Emergency events.

EDR Participants shall be entitled to receive compensation for reducing Demand only to the extent that the EDR Participants comply with the Transmission Provider's EDR Dispatch Instructions. EDR Participants shall not be entitled to compensation for Demand reductions in excess of the EDR Dispatch Instruction amounts (*i.e.*, if Demand was reduced by more than that requested by the Transmission Provider in an EDR Dispatch Instruction), provided that EDR Participants shall be entitled to proportionate compensation if they reduced Demand by a proper fraction of the EDR Dispatch Instruction. If an EDR Participant reduces Demand by more than the EDR Dispatch Instruction during an Emergency event, the EDR Participant will not be allocated Real-Time Revenue Sufficiency Guarantee Charges for deviations in Load, pursuant to Section 40.3.3.2. To the extent that an EDR Demand reduction would have occurred during the EDR Dispatch Instruction time period absent the Transmission Provider issuing an EDR Dispatch Instruction to the EDR Participant, then the EDR Participant will not be entitled to compensation for such Demand reduction.

VI. MEASUREMENT AND VERIFICATION PROCEDURES

Unless an alternate approach is agreed upon by the Transmission Provider and an EDR Participant and such alternate approach is documented in Attachment TT of the Tariff, measurement and verification for EDR Participants with hourly interval Metered data will be based upon actual hourly use in the Hour immediately preceding notification to the EDR Participant of the EDR Dispatch Instruction by the Transmission Provider. If Emergency events occur during sequential days, the relevant data will be based upon the actual hourly usage prior to the first of the sequential Emergency event days.

Except as may otherwise be agreed to, EDR Participants must provide the Transmission Provider with meter information for the Hour prior to notification of the EDR Dispatch Instruction, as well as every Hour during the Demand reduction, except under the following circumstances. When on-site generation is deployed exclusively to support the Demand reduction, the EDR Participant may provide qualified meter data from the on-site generation for each Hour of the Emergency event day. Provision of hourly meter data from the on-site generation will be deemed a certification by the EDR Participant that the on-site generation was not used for any purpose other than to support the Demand reduction during the Emergency event day.

An EDR Participant that achieves Demand reduction through the use of direct load control procedures must provide the Transmission Provider with proposed Measurement and Verification procedures. These procedures must be consistent with Attachment TT in the Tariff and include: (1) a description of the direct Load control system, including communication technology, type of Load(s) which are controlled, proposed control scheme (e.g. cycling or complete Load shed), number of participants, geographic location of participants and other relevant information; (2) a description of Load research data that is used in the analysis; (3) a description of the formulae used to produce the estimate, including all assumptions; and (4) a description of all source information for variables used in the analysis, such as a schedule of Demand reductions according to the time of day and weather conditions (e.g., temperature and humidity index). The Transmission Provider may request additional information from such EDR Participant and/or request appropriate revisions to the proposed Measurement and Verification procedures.

EDR Participants must provide the meter data and/or the results of the direct Load control Measurement and Verification procedures, as specified in the Business Practices Manuals, to the Transmission Provider within fifty-three (53) Calendar Days after the Demand reduction, in order to be eligible to receive compensation.

VII. COMPENSATION

EDR Participants that reduce Demand in response to an EDR Dispatch Instruction from the Transmission Provider shall receive the higher of the applicable Hourly Real-Time Ex Post LMP revenue for the associated CPNode of the EDR Participant or the EDR cost recovery during the period of actual Demand reductions. EDR cost recovery is the sum of (i) the shutdown cost and (ii) the lesser of (a) the amount of hourly verifiable Demand reduction or (b) the hourly Dispatch Instruction for each Hour multiplied by the hourly curtailment offer during the period of actual Demand reductions.

EDR Participants must submit documentation of Demand reductions made in response to EDR Dispatch Instructions to enable the EDR Participant to verify in writing under oath to the Transmission Provider that the Demand reductions actually occurred during an Emergency event. EDR Participants must verify in writing to the Transmission Provider that the amount of Demand reductions were made in direct response to the Transmission Provider's EDR Dispatch Instruction and that the Demand reductions otherwise would not have been made.

EDR Participants that receive EDR Dispatch Instructions in response to submitted EDR offers but do not reduce Demand in response to an EDR Dispatch Instruction from the Transmission Provider to the levels specified in the EDR Dispatch Instruction, and adjusted for the Demand Reduction Tolerance, shall not be guaranteed cost recovery for such failure to make Demand reductions. The Demand Reduction Tolerance is equal to (i) the EDR Dispatch Instruction MWhs multiplied by ninety-five percent (95%). EDR Participants that reduce Demand in response to an EDR Dispatch Instruction between the levels specified in the EDR Dispatch Instruction and the Demand Reduction Tolerance will be guaranteed cost recovery for provision of Demand reductions. In addition, such EDR Participants failing to reduce Demand shall be charged an amount equal to the Demand Reduction Shortfall multiplied by the Hourly Real-Time Ex Post LMP of the associated Load CPNode. The Demand Reduction Shortfall is calculated as: (i) the Demand Reduction Tolerance minus the actual Demand reduction; or (ii) zero (0), whichever is greater.

Any reductions in Demand by an EDR Participant shall be subject to verification and potential investigation by the Transmission Provider and the Federal Energy Regulatory Commission to confirm the validity of all EDR Participant assertions.

VIII. PAYMENTS

The sum of the EDR Initiative payments made in an Hour in excess of market revenues shall be funded through an assessment of debits on Market Participants on a *pro rata* basis, based on the Metered Load Ratio Share in the local Balancing Authority Area(s) where the Emergency event occurred that served Load during the EDR Dispatch Instruction period in that same Hour. Any credits that result from EDR Participant(s) failure to reduce Demand as described in Section V shall be allocated in the same *pro rata* basis as costs are allocated in Section VI.

Tab B

Eastern Interconnection: The ERO certified Balancing Authorities operating in the eastern part of North America.

Eastern Prevailing Time (EPT): Eastern Daylight Time during periods when the eastern time zone is observing daylight saving time, Eastern Standard Time during periods when the eastern time zone is observing standard time.

Economic Maximum Dispatch: The maximum MW level at which a Resource may be dispatched by the Transmission Provider in real-time for Energy under normal system conditions. For Intermittent Resources or Resources incapable of following Setpoint Instructions, the Economic Maximum Dispatch will equal the Actual Energy Injections.

Economic Minimum Dispatch: The minimum MW level at which a Resource may be dispatched by the Transmission Provider in real-time for Energy under normal system conditions. For Intermittent Resources or Resources incapable of following Setpoint Instructions, the Economic Minimum Dispatch will equal the Actual Energy Injections.

Effective Import Tie Capability (EITC): The maximum aggregate level of power in MW that can be reasonably expected to flow on the transmission tie lines into a specified Zone of the Transmission System, while maintaining reliable operation.

Effective Export Tie Capability (EETC): The maximum aggregate level of power in MW that can be reasonably expected to flow outward on the transmission tie lines of a specified Zone of the Transmission System, while maintaining reliable operation.

Electric Distribution Company (EDC): A company that distributes electricity to retail customers through distribution substations and/or lines owned by the company.

Electric Facility: Equipment used for the generation, transmission, storage, or control of the transmission of electricity and that is connected to or part of the Transmission System operated by the Transmission Provider.

Electric Generation and Transmission Cooperative (Coop): An electric Generation and Transmission cooperative is a not for profit rural electric system whose primary function is to provide electric power on a wholesale basis to its owners.

Electric Reliability Organization (ERO): The organization certified by the Commission to establish and enforce reliability standards for the bulk-power system, subject to Commission review.

Electric Storage Resource (ESR): A Resource capable of receiving Energy from the Transmission System and storing it for later injection of Energy back to the Transmission System. This definition includes all technologies and/or storage mediums, including but not limited to, batteries, flywheels, compressed air, and pumped-hydro. The location of an ESR may be at any point of grid interconnection, on either the Transmission System or a local distribution system, but must not be outside the Transmission Provider Region. An ESR must: (1) be capable of injecting and withdrawing a minimum of 0.1 MW; (2) be capable of complying with the Transmission Provider's Setpoint Instructions; (3) have the appropriate metering equipment installed; and (4) be physically located within the MISO Balancing Authority Area. The State of Charge shall be managed by the Market Participant operating the ESR. An ESR shall also be deemed a Generator based on, and in contexts relevant to, its capability to inject Energy back into the Transmission System.

Electric Storage Resource Efficiency Factor: An operating characteristic of an Electric Storage Resource that is the amount of increase in Energy Storage Level for each 1 MWh of Charge Energy withdrawn by that Resource.

Electric Storage Resource Offer: An Offer submitted by a Market Participant within the MISO Balancing Authority Area for the output of a specified Electric Storage Resource to supply Energy, Capacity, Online Short-Term Reserve, Up Ramp Capability, Down Ramp Capability, Spinning Reserve, Supplemental Reserve and/or Regulating Reserve to the Energy and Operating Reserve Markets.

Electric Storage Resource Owner: An entity that owns, leases with rights equivalent to ownership in, and controls the output of or operates Electric Storage Resources.

Electric Storage Resource Transaction: Market Activities associated with the charging and discharging process of an Electric Storage Resource that consist of the withdrawal of Energy from the Transmission System, including any associated Energy purchases, and future injection of Energy, including any associated Energy sales, to the Transmission System under this Tariff.

Elemental Pricing Node (EPNode): A single Bus where LMP is calculated.

Eligible Confirmed Transmission Service Reservation: Any reservation for Transmission Service that has been confirmed and has a start date later than the date a Default first occurs. Any reservation for Transmission Service that has been confirmed remains a conditionally approved request at all times prior to such reservation's start date and may be cancelled if a Default occurs prior to such start date.

Eligible Customer: (i) Any electric utility (including the Transmission Owner(s), ITC Participants(s), and any power marketer), Market Participant, Federal Power Marketing Agency, or any person generating electric Energy for sale or for resale is an Eligible Customer under this Tariff. Electric Energy sold or produced by such entity may be electric Energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by § 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that a Transmission Owner or ITC Participant offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner or ITC Participant; or (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that a Transmission Owner or ITC Participant offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner or ITC Participant, that is an Eligible Customer under this Tariff. Unbundled retail customers that seek to take local distribution service cannot be Eligible Customers under this Tariff with respect to that service.

Eligible Projects: Shall mean any Market Efficiency Projects ("MEP") and Multi-Value Projects ("MVP") approved by the Transmission Provider's Board after December 1, 2015 regardless of whether such project is subject to the Transmission Provider's Competitive Developer Selection Process.

Emergency**:** (i) An abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm Load, equipment damage, or tripping of system elements that could adversely affect the reliability of any electric system or the safety of persons or property; (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of Emergency procedures as defined in this Tariff.

Emergency Demand Response (EDR): The commitment and dispatch of Load reductions, Behind the Meter Generation Resources and other Demand Resources during an Emergency, in accordance with Schedule 30.

EDR Dispatch Instruction: Directives issued by the Transmission Provider to EDR Participants indicating MW quantities to be reduced during Emergencies.

EDR Initiative: Procedures for EDR Participants to respond to an Emergency through a defined reduction in Load or increase in output from Behind the Meter Generation Resources, as described in Schedule 30 of this Tariff.

EDR Offer: An offer made by an EDR Participant to reduce demand in response to an Emergency event which will not be considered in the clearing of the Day-Ahead Energy and Operating Reserve Market or Real-Time Energy and Operating Reserve Markets.

EDR Participant: A Market Participant capable of reducing demand in response to directives received from the Transmission Provider during an Emergency event.

Emergency Energy: Purchases of Energy coordinated by the Transmission Provider following the issuance of an Energy Emergency Alert in accordance with the procedure set forth in Section 40.2.22 of this Tariff.

Emergency Maximum Energy Storage Level: State of Charge value that should not be exceeded when an Electric Storage Resource is being Charged while providing Energy or Operating Reserves under Emergency conditions.

Emergency Minimum Energy Storage Level: State of Charge value that should not be exceeded when an Electric Storage Resource is being Discharged while providing Energy or Operating Reserves under Emergency conditions.

Emergency Operating Procedures: Procedures coordinated by the Transmission Provider prior to and during Energy Emergencies.

Emergency Operations Resource: An online Generation Resource that is not an online Fast Start Resource and is started, synchronized and injects Energy, or a Demand Response Resource that reduces its Energy consumption, within two hundred forty (240) minutes of being notified and that has a minimum run time of less than four hours and that will participate in setting price as described in the process in Schedule 29A of this Tariff.

Emergency Operations Resource All-In Energy Offer: The sum of an online Emergency Operations Resource's Energy Offer, its amortized No Load Offer and, during its Minimum Run Time, its amortized Start up Offer; provided, that, in the case of a Demand Response Resource – Type I, it shall be the sum of the Energy Offer, its amortized Hourly Curtailment Offer and its amortized Shut-Down Offer over its minimum interruption duration.

Emergency Operations Resource All-In Reference Level: The sum of an online Emergency Operations Resource's Energy Reference Level, its amortized No Load Reference Level and, during its Minimum Run Time, its amortized Start up Reference Level; provided, that, in the case of a Demand Response Resource – Type I, it shall be the sum of the Energy Reference Level, its amortized Hourly Curtailment Offer Reference Level and its amortized Shut-Down Offer Reference Level over its minimum interruption duration.

Emergency System Conditions: Are (i) situations in which a systemic equipment malfunction, including telecommunications, hardware, or software failures, prevents the Transmission Provider from operating the Energy and Operating Reserve Markets in accordance with the Market Rules; or (ii) widespread electric transmission or generation equipment outages that prevent the Transmission Provider from dispatching the system in accordance with the Market Rules.

Emergency Tier I Offer Floor: The minimum Proxy Offer established by the Transmission Provider, as specified in Schedule 29A, following the declaration of maximum generation emergency warning as specified in the Transmission Provider's Emergency Operating Procedures. The maximum value of the Emergency Tier I Offer Floor will be the Energy Offer Hard Price Cap.

Emergency Tier II Offer Floor: The minimum Proxy Offer established by the Transmission Provider, as specified in Schedule 29A, following the declaration of maximum generation emergency event, step 2 as specified in the Transmission Provider's Emergency Operating Procedures. The maximum value of the Emergency Tier II Offer Floor will be the Energy Offer Hard Price Cap.

Energy: An amount of electricity that is Bid or Offered, produced, purchased, consumed, sold, injected, withdrawn, or transmitted over a period of time and measured or calculated in megawatt hours (MWh).

Energy and Operating Reserve Market(s): The Day Ahead and/or Real Time Energy and Operating Reserve Markets operated by the Transmission Provider.

Energy Consumer: Any end-use customer, including but not limited to commercial retail consumers of electricity, located within the Transmission Provider Region.

Energy Deficient Region: An area in which one or more LSEs within the MISO Balancing Authority Area are experiencing or are expected to experience an Emergency under the procedures specified under Section 40.2.20 of this Tariff.

Energy Efficiency Resource (EE Resource): A Planning Resource consisting of installed measures on retail customer facilities that achieves a permanent reduction in electric energy usage while maintaining a comparable quality of service.

Energy Emergency: A condition when a balancing authority can no longer meet the energy requirements of the firm end-use load within its balancing authority area and has initiated its Energy Emergency procedures**.**

Energy Emergency Alert: An alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area.

Energy Emergency Area: The area within a balancing authority area that is experiencing an Energy Emergency.

Energy Emergency Alert – Level 2 (EEA-Level 2): Energy Emergency Alert Level 2 as defined by NERC.

Energy Emergency Alert – Level 3 (EEA-Level 3): Energy Emergency Alert Level 3 as defined by NERC, indicating that firm load interruption is imminent or in progress.

Energy Management System (EMS): The software system used by the Transmission Provider and Transmission Operators for acquisition and processing of operational data.

Energy Market Counterparty: The Transmission Provider as the contracting counterparty to Market Participants for all Market Activities contemplated by this Tariff, solely in the Transmission Provider's capacity as a principal and not as an agent for any other party, consistent with the provisions of Section 6A.

Energy Offer: The price at which a Market Participant has agreed to sell the next increment of Energy from a Generation Resource, Demand Response Resource – Type I, Demand Response Resource-Type II, or the price at which a Market Participant has agreed to sell Energy via a Dispatchable Interchange Schedule Import Schedule; or the price at which a Market Participant has agreed either to import or export the next increment of Energy from an External Asynchronous Resource; or the price at which a Market Participant has agreed to either buy (Charge) or sell (Discharge) the next increment of Energy from an Electric Storage Resource.

Energy Offer Hard Price Cap: The maximum price permitted for a Verified Energy Offer, a Verified Fast Start Resource All-In Energy Offer, or a Verified Emergency Operations Resource All-In Energy Offer, to set price in the Energy and Operating Reserve Markets. The Energy Offer Hard Price Cap is $2,000/MWh.

Energy Offer Soft Price Cap: The maximum price permitted for an incremental Energy Offer, a Fast Start Resource All-In Energy Offer, or an Emergency Operations Resource All-In Energy Offer, to set price in the Energy and Operating Reserve Markets without prior cost verification by the Independent Market Monitor, subject to mitigation under Module

D when the Energy Offer, the Fast Start Resource All-In Energy Offer, or the Emergency Operations Resource All-In Energy Offer, cost exceeds the applicable Reference Level. The Energy Offer Soft Price Cap is $1,000/MWh. The Transmission Provider shall also verify Fast Start Resource All-In Energy Offers and Emergency Operations Resource All-In Energy Offers pursuant to section 64.1.4.a.iii.d of Module D.

Energy Offer Price Floor: The minimum price permitted for an Energy Offer in the Energy and Operating Reserve Markets.

Energy Resource Interconnection Service: The interconnection of a Generation Resource to the Transmission System or distribution system, as applicable, to be eligible to deliver the Generation Resource's electric output using the existing firm or non-firm capacity of the Transmission System on an as available basis.

Energy Storage Level: The stored Energy available to the Transmission Provider's markets for Energy or Operating Reserves from a Resource.

EPT: Eastern Prevailing Time.

Equity: For credit scoring purposes, the ownership interest in a firm, including the residual dollar value of a futures trading account, assuming its liquidation is at the going trade price of Applicant or Market Participant.

Equivalent Forced Outage Rate Demand (EFORd): The Equivalent Forced Outage Rate Demand, as defined by NERC.

EST: Eastern Standard Time.

Ex Ante MCP: The Regulating Reserve MCP, Regulating Mileage MCP, Spinning Reserve MCP, Supplemental Reserve MCP, Up Ramp Capability MCP, Down Ramp Capability

MCP, and Short-Term Reserve MCP calculated at the beginning of the Dispatch Interval, used for informational purposes in the Real-Time Energy and Operating Reserve Market.

Ex Post MCP: The Regulating Reserve MCP, Regulating Mileage MCP, Spinning Reserve MCP, Supplemental Reserve MCP, Up Ramp Capability MCP, Down Ramp Capability MCP, and Short-Term Reserve MCP calculated for each Dispatch Interval.

Excess Congestion Charge Fund: A fund established by the Transmission Provider representing, in aggregate, the difference between the total of all Transmission Congestion Payments for a given Hour and the hourly transmission congestion charges.

Excessive/Deficient Charge Rate: The rate used to determine a Resource's Excessive/Deficient Energy Deployment Charge as calculated pursuant to Section 40.3.4.b.

Excessive/Deficient Energy Deployment Charge: A charge assessed to any Resource in an Hour with Excessive Energy and/or Deficient Energy in four (4) or more consecutive Dispatch Intervals within the Hour.

Excessive Energy: The amount of a Generation Resource's, Electric Storage Resource's, or External Asynchronous Resource's Actual Energy Injection at a Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market in a Dispatch Interval that is greater than that Resource's Excessive Energy Threshold or, the amount of a Demand Response Resource's Type I Calculated DRR Type I Output, as adjusted for Actual Energy Injection or Demand Response Resource's Type II Calculated DRR Type II Output, at a Commercial Pricing Node in the Real Time Energy and Operating Reserve Market in a Dispatch Interval that is greater than that Resource's Excessive Energy Threshold.

Excessive Energy Threshold: The maximum value of a Resource's Tolerance Band.

Excessive Energy Tolerance: The MW difference between (1) the Excessive Energy Threshold and (2) the average of the Dispatch Targets for Energy for the current Dispatch Interval and the previous Dispatch Interval plus the average Regulating Reserve Deployment instruction for that Dispatch Interval.

Excessive Withdrawal: The amount of an Electric Storage Resource's Actual Energy Injection at a Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market in a Dispatch Interval that is less than the minimum of the Deficient Energy Threshold or zero (0).

Expected Unserved Energy (EUE): In the probabilistic study, an estimate of the energy that would otherwise have been used by end use customers but for a supply interruption.

Export Schedule: An Interchange Schedule in which the Interchange Schedule Receipt Point lies within the MISO Balancing Authority Area and the Interchange Schedule Delivery Point lies outside the MISO Balancing Authority Area.

Exporting Entity: A Market Participant that is not a Load Serving Entity with a cleared Export Schedule in the Day-Ahead Energy and Operating Reserve Market or an Export Schedule in the Real-Time Energy and Operating Reserve Market.

Extended Locational Marginal Price (ELMP): The Transmission Provider shall implement, ELMP, an enhanced pricing mechanism expanding upon LMP and MCP in which additional resources, including resources that are scheduled to operate at limits, certain off-line resources, and the start-up or shut-down and no-load or curtailment costs of resources may be included in the calculation of prices at the Commercial Pricing nodes located throughout the Transmission Provider region. Such prices shall be calculated per the process set forth in Schedule 29A.

Extended Transmission Outage: A Planned Transmission Outage that exceeds the original outage schedule previously provided by the Transmission Owner to the Transmission Provider.

External Asynchronous Resource: A Resource representing an asynchronous DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid that is supported within the Transmission Provider Region through Dynamic Interchange Schedules in the Day-Ahead Energy and Operating Reserve Market and/or Real-Time Energy and Operating Reserve Market. External Asynchronous Resources are located where the asynchronous tie terminates in the synchronous Eastern Interconnection grid.

External Resource: A generator located outside of the metered boundaries of the MISO Balancing Authority Area.

External Resource Zone (ERZ): A grouping of one or more External Resources in the same external balancing authority for purposes of the Planning Resource Auction.

Extreme Event: An event which includes, but is not limited to, extreme weather events, or other emergency events that have a severe short-term impact on market pricing. Such an event may be declared by the Transmission Provider in its sole discretion and shall affect the applicable Credit Policy calculations as set forth in within Attachment L.

Legitimate Risks: Business operation risks, incurred by a Market Participant, that increase as a result of providing any of the products described in the Tariff. These risks include, but are not limited to, the risk of repair expenses; business interruption due to outages resulting from either a failure to start, or unplanned outages that occur when the facility is in service; regulatory restrictions; and disruptions from labor relations problems. These risks are in the nature of marginal costs included in Reference Levels. In contrast, the risk associated with fuel purchase price is not a component of Reference Levels, but rather a basis for the Fuel Cost Uncertainty Adder and some of the conduct thresholds under Module D.

Letter of Credit: A Credit Support Document taking the form found in Exhibit II of Attachment L to this Tariff.

Line Outage Distribution Factor (LODF): The percent of flow on line A, which is transferred to line B for the loss of line A.

Load: A term that refers to either an end-user of Energy, net of system losses, or the amount of Energy (MWh) consumed by such end-user within the Transmission Provider Region.

Load Forecast: An estimate of the amount of Energy (MWh) or Capacity (MW) to be consumed within the Transmission Provider's Region, prepared by the Transmission Provider based upon input from Local Balancing Authorities and Load Serving Entities, and used in the Transmission Provider's scheduling and dispatch decisions to ensure reliable operation of the MISO Balancing Authority.

Load Modifying Resource: A Demand Resource or Behind the Meter Generation Resource.

Load Modifying Resource Market Participant (LMR MP): A Market Participant that has the rights to control the energy demand or the energy production from a Load Modifying Resource.

Load Ratio Share: Ratio of a Transmission Customer's Network Load in a Zone to the total Load in that pricing Zone computed in accordance with Module B, Section 34.2 of this Tariff.

Load Serving Entity (LSE): Any entity that has undertaken an obligation to serve Load for end-use customers by statute, franchise, regulatory requirement or contract for Load located within or attached to the Transmission System, including but not limited to purchase-selling entities and retail power marketers with the obligation to serve Load. Where a distribution cooperative or a municipal distribution system otherwise covered by the prior sentence is a wholesale customer of a generation and transmission cooperative or a municipal Joint Action Agency, the generation and transmission cooperative, a state or federal agency or municipal Joint Action Agency may act as the Load Serving Entity for such distribution cooperative or municipal distribution system. Where retail Load switching occurs in a state, the entity with the obligation to serve Load is the LSE

Load Shedding: The systematic reduction of system demand by temporarily decreasing Load in response to a Transmission System Emergency, Local Transmission Emergency, or MISO Balancing Authority Area or Sub-Area Capacity shortages, system instability, or voltage control considerations under Module B and Module C, of this Tariff.

Load Zone: A Zone determined by Market Participants representing an aggregate area of consumption for a single Load Serving Entity within the MISO Balancing Authority Area and used for the purposes of scheduling, reporting Actual Energy Withdrawal volumes, and settling Energy transactions at aggregated Load levels, approved and maintained by the Transmission Provider to facilitate transactions.

Local Balancing Authority (LBA): An operational entity or a Joint Registration Organization which is (i) responsible for compliance to NERC for the subset of NERC Balancing Authority Reliability Standards defined in the Balancing Authority Agreement for their local area within the MISO Balancing Authority Area, (ii) a Party to Balancing Authority Agreement, excluding MISO, and (iii) shown in Appendix A to the Balancing Authority Agreement.

Local Balancing Authority Area: Shall have the meaning set forth in the Balancing Authority Agreement.

Local Clearing Requirement (LCR): The minimum amount of Seasonal Accredited Capacity for an LRZ that is required to meet its LOLE for each Season while fully using the Zonal Import Ability for such LRZ and accounting for controllable exports.

Local Clearing Requirement Charge: A charge that is assessed to Load Serving Entities whenever an LRZ's Auction Clearing Price for a Season is increased due to its LCR being greater than the sum of individual Final PRMR of the LSEs.

Local Reliability Requirement (LRR): The minimum amount of Unforced Capacity for an LRZ to meet its LOLE for each Season, without considering transmission ties to systems outside of the LRZ.

Local Resource Zone (LRZ): A geographic area within the Transmission Provider Region that is prescribed by the Transmission Provider, based upon the criteria in Section 68A.3, to address congestion that limits Planning Resource deliverability.

Local Resource Zone Peak Demand: The Demand in MWs, for an LSE and/or EDC, in a Local Resource Zone that occurs coincident to the peak Demand for each Season in the Local Resource Zone, where all Demand has been augmented to include any known reductions in Demand related to LMRs and/or Energy Efficiency Resources.

Local Short-Term Reserve: Short-Term Reserve available to the Transmission Provider to address transmission constraints in any Reserve Zone(s).

Local Short-Term Reserve Requirements: The amount of Local Short-Term Reserve, as determined pursuant to Module C of the Tariff, that the Transmission Provider is required to procure in a Reserve Zone.

Local Transmission Emergency: Transmission System conditions or events that have the potential to exceed or have exceeded operating limits that do not pose a risk of cascading to the interconnection but require emergency-level actions.

Locational Marginal Price (LMP): A price for Energy at a given Commercial Pricing Node in the Transmission Provider Region which is the marginal cost of serving demand at the Commercial Pricing Node while meeting Zonal and Market-Wide Operating Reserve Requirements, Up Ramp Capability requirements, Down Ramp Capability requirements, and Short-Term Reserve Requirements. Such price may be either Ex Ante or Ex Post.

Long-Term Firm Point-To-Point Transmission Service: Firm Point To Point Transmission Service under Module B of this Tariff with a term of one (1) year or more.

Long Term Transmission Rights (LTTR): ARRs allocated in Stage 1A of the Annual ARR Allocation process. LTTRs carry annual rollover rights lasting ten (10) years or more.

Look Ahead Commitment (LAC): A process performed during the Real-Time Energy and

Operating Reserve Market that develops Resource commitment and decommitment options that may be used by the Transmission Provider to ensure sufficient Resources will be available to meet Load Forecast, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve and other demand requirements for the near term intra-hour intervals.

Loss of Load Expectation (LOLE): The sum of the loss of Load probability for the integrated daily peak Hour for each Day of the year.

Loss of Load Probability Curve: The probability of shedding firm Load under varying levels of Contingency Reserve shortages, to be used in accordance with Schedule 28. This curve is further described in the Transmission Provider's Business Practices Manual for the Energy and Operating Reserves Markets (BPM-002).

Loss Pools: A single Local Balancing Authority Area or an aggregation of Local Balancing Authority Areas, including those Local Balancing Authority Areas operated by Coordinating Owners consistent with the terms and provisions of the Coordinating Owners agreement, designated by the Transmission Provider for the purposes of calculating and distributing Day Ahead and Real Time Hourly Marginal Losses Revenue Surplus.

Lost Opportunity Cost: The LMP revenues that were not realized relative to a theoretical future operating point.

Value of Lost Load – Pricing (Pricing VOLL): The value that represents the price consumers are willing to pay to avoid an interruption of electrical service during a EEA-Level 3, which is based on consumers with the lowest willingness to pay. The Pricing VOLL shall default to $10,000/MWh, and shall be reduced when necessary, as set forth in section 40.2.20.b.iv of this Tariff..

Value of Lost Load – System (System VOLL): The value that represents the price consumers are willing to pay to avoid an interruption of electrical service. The System VOLL shall be equal to $35,000/MWh, and shall be used to scale the Loss of Load Probability Curve when calculating the Operating Reserve Demand Curve specified in Schedule 28.

Variance Analysis: Additional analysis performed by the Transmission Provider in accordance with Section IX of Attachment FF to the Tariff.

Verified Energy Offer: A Resource's cost-based incremental Energy Offer above the Energy Offer Soft Price Cap, verified by the Independent Market Monitor after the close of the Day-Ahead Energy and Operating Reserve Market or the Real-Time Energy and Operating Reserve Market and before market clearing.

Verified Fast Start Resource All-In Energy Offer: A Fast Start Resource All-In Energy Offer that exceeds the Energy Offer Soft Price Cap, and was verified by the Transmission Provider pursuant to section 64.1.4.a.iii.d of Module D before market clearing.

Virtual Bid: A bid to purchase Energy that is not backed by physical Load that is submitted in the Transmission Provider's Day Ahead Energy and Operating Reserve Market in accordance with the procedures and requirements of this Tariff.

Virtual Energy: Energy purchased and/or sold in the Day Ahead Energy and Operating Reserve

Market that is not backed by real assets such as Load or Generation Resources.

Virtual Megawatt Hour Limit (Virtual MWh Limit): The limit on MWh of Virtual Bids and Virtual Supply Offers that may be submitted by a Tariff Customer on a given Operating Day, as established and modified pursuant to Section IV.A of Attachment L of this Tariff.

Virtual Supply Offer: An Offer to sell Energy that is not backed by a physical Resource that is submitted in the Transmission Provider's Day Ahead Energy and Operating Reserve Market in accordance with the procedures and requirements of this Tariff.

Virtual Transactions: Transactions related to Virtual Bids and/or Virtual Supply Offers.

Voltage and Local Reliability Commitment: A Transmission Provider issued Resource commitment in addition to, in lieu of or resulting from the Security Constrained Unit Commitment in the Day-Ahead Energy and Operating Reserve Market or any Reliability Assessment Commitment, in order to mitigate issues with Transmission System voltage or other local reliability concerns. These Resource commitment requirements are established prior to or during an Operating Day and are based on projected local reliability requirements, operational considerations, and generation and transmission outages. VLR Commitments will be based on Operating Guides for recurring voltage and local reliability requirements, but an Operating Guide is not required prior to a Resource commitment being designated as a VLR Commitment. Resource commitments to relieve a potential or actual IROL violation will not be designated in this category.

Voltage and Local Reliability Commitment Allocation Ratio: The ratio of RSG costs associated with Voltage and Local Reliability Commitments allocated to Local Balancing Authority Areas. The ratio is determined by the Transmission Provider as described in Schedule 44 of this Tariff.

Voltage and Local Reliability Local Balancing Authority Area Share: The pro rata allocation to each Local Balancing Authority Area of Revenue Sufficiency Guarantee Charges associated with Voltage and Local Reliability Commitments. The Voltage and Local Reliability Local Balancing Authority Area Share will be determined by the Transmission Provider as described in Schedule 44 of this Tariff.

Voltage and Reactive Power Coordination Procedures: The procedures that the Transmission Provider and the Congestion Management Customer shall establish to ensure the reactive power support necessary to maintain transmission voltages within limits that are established by the Transmission Provider, which are measured in MVAR.

Day-Ahead Energy and Operating Reserve Market Trading Deadline:

No later than the close of the Day-Ahead Energy and Operating Reserve Market, (1) Market Participants, including GFA Scheduling Entities and Market Participants with SSR Units, must submit to the Transmission Provider any Interchange Schedules, Bids for the purchase of Energy; Self-Schedules and/or Offers for the sale of Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, and Short-Term Reserve; and Offer Dispatch Status for Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve for consideration in the Day-Ahead Energy and Operating Reserve Market; and (2) Market Participants must indicate for each Hour of the Operating Day if Resources are to be self-committed or economically committed. The Day-Ahead Energy and Operating Reserve Market shall close at 1030 hours EPT, or such later time as may be required from time to time due to unanticipated events, the Day before the Operating Day. The Transmission Provider may extend or reopen the Day-Ahead Energy and Operating Reserve Market based on unanticipated events that: (i) interfere with the Transmission Provider's ability to receive or process Bid, Offer, or Interchange Schedule data; (ii) render Bid, Offer, or Interchange Schedule data plainly inaccurate in a manner that is likely to significantly impede the Transmission Provider's ability to deliver a feasible market solution; (iii) are otherwise likely to have a widespread negative impact on the results of the Day-Ahead Energy and Operating Reserve Market, in a manner that adversely threatens or affects the reliability of market operations or of the Transmission System; or (iv) require adjustments to the Pricing VOLL in accordance with Section 40.2.20.b.iv. The Transmission Provider shall post a notice of any extension or reopening of the Day-Ahead Energy and Operating Reserve Market. The notice shall state each extension or reopening's circumstances, rationale, duration, and whether such action enabled the Transmission Provider to successfully address or minimize the issue that necessitated the extension or reopening.

Demand Bid Rules in the Day-Ahead Energy and Operating Reserve Market:

a. General Demand Bid Rules. Market Participants that intend to purchase Energy in the Day-Ahead Energy and Operating Reserve Market shall submit Fixed Demand Bids and/or Price Sensitive Demand Bids and shall provide the Bid information specified in this Section. Only Market Participants that have demonstrated to the Transmission Provider's satisfaction that they are Load Serving Entities or are purchasing on behalf of Load Serving Entities may submit Demand Bids. The Transmission Provider shall maintain a list of Commercial Pricing Nodes that may be specified in Demand Bids by Market Participants.

b. Fixed Demand Bid Components. Fixed Demand Bids shall include:

i. The Commercial Pricing Node registered by the Market Participant for which it intends to purchase the designated MWh of Energy.

ii. Hourly MWh quantities, with a default of zero (0) MWh.

c. Price Sensitive Demand Bid Data. Price Sensitive Demand Bids shall include:

i. Commercial Pricing Node registered by the Market Participant for which it intends to purchase the designated MWh of Energy.

ii. A maximum of nine (9) bid blocks for each Hour, where each Bid block specifies a maximum price ($/MWh), and MWh quantity.

a. **General Virtual Bid Rules.** Market Participants that intend to purchase Virtual Energy in the Day-Ahead Energy and Operating Reserve Market shall provide the Bid information specified in this Section. Market Participants may purchase Virtual Energy at any Commercial Pricing Node. Virtual Bids may not be used to purchase Operating Reserve.

b. **Virtual Bid Components.** Virtual Bids shall include:

i. The Commercial Pricing Node where the Market Participant desires to purchase the designated MWh of Energy.

ii. A maximum of nine (9) bid blocks for each Hour, where each Bid block specifies a maximum price ($/MWh) and MWh quantity.

The Transmission Provider shall use SCUC, SCED, and SCED-Pricing algorithms to: (i) commit Resources; (ii) clear Offers, Bids, Self-Schedules, Interchange Schedules, and Virtual Transactions; (iii) establish Day-Ahead Schedules, Day-Ahead Ex Ante LMPs, and Day-Ahead Ex Ante MCPs; and (iv) establish Day-Ahead Ex Post LMPs and Day-Ahead Ex Post MCPs, for each Hour of the Operating Day.

a. Determination of Day-Ahead Schedules.

In the Day-Ahead Energy and Operating Reserve Market, the Transmission Provider shall determine: (i) Energy Schedules for Resources, Load Zones, Interchange Schedules, and Virtual Transactions; (ii) Operating Reserve Schedules for Resources; (iii) Up Ramp Capability and Down Ramp Capability Schedules for Resources; and (iv) Short-Term Reserve schedules for Resources.

b. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at Elemental Pricing Nodes.

The Transmission Provider shall calculate Day-Ahead Ex Ante LMPs for each Hour and Elemental Pricing Node in the Day-Ahead Energy and Operating Reserve Market using the SCED algorithm. The Day-Ahead Ex Ante LMP at an Elemental Pricing Node in a specific Hour is the marginal Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve and, if applicable, Reserve Scarcity costs, Up Ramp Capability scarcity costs, Down Ramp Capability scarcity cost, and/or Short-Term Reserve scarcity costs to supply Energy to Load at the Elemental Pricing Node during the Hour using the SCED algorithm. The Day-Ahead Ex Post LMPs will be based upon the SCED-Pricing algorithm described in Schedule 29A. The Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs are based on: (i) Generation Offers; (ii) Demand Response Resource–Type II Offers; (iii) External Asynchronous Resource Offers; (iv) Virtual Supply Offers; (v) Price Sensitive Demand Bids; (vi) Dispatchable Interchange Schedules; (vii) Up-to-TUC Interchange Schedules; (viii) Virtual Bids; (ix) Demand Curves; (x) Electric Storage Resource Offers; and (xi) Proxy Offers when appropriate as specified in Schedule 29A.

i. Calculation of Marginal Congestion Component.

For each Day-Ahead Ex Ante LMP and Day-Ahead Ex Post LMP, the Transmission Provider will calculate the Cost of Congestion at each Elemental Pricing Node as a component of the LMP (the Marginal Congestion Component). The Marginal Congestion Component of a Day-Ahead Ex Ante LMP reflects the marginal cost of managing transmission congestion and enforcing Sub-Regional Power Balance Constraints, that will arise from an incremental Energy demand at the Elemental Pricing Node supplied by an incremental Energy injection at the Reference Bus in the SCED algorithm. The Marginal Congestion Component of a Day-Ahead Ex Post LMP reflects the marginal cost of managing transmission congestion and enforcing Sub-Regional Power Balance Constraints, that will arise from an incremental Energy demand at the Elemental Pricing Node supplied by an incremental Energy injection at the Reference Bus in the SCED-Pricing algorithm.

ii. Calculation of Marginal Losses Component.

For each Day-Ahead Ex Ante LMP and Day-Ahead Ex Post LMP, the Transmission Provider will calculate the Cost of Losses at each Elemental Pricing Node as a component of the LMP at that Elemental Pricing Node (the Marginal Losses Component). The Marginal Losses Component of any Day-Ahead Ex Ante LMP reflects the marginal cost of serving System Losses that arise from an incremental Energy demand at the Elemental Pricing Node supplied by a loss adjusted Energy injection at the Reference Bus in the SCED algorithm. The Marginal Losses Component of any Day-Ahead Ex Post LMP reflects the marginal cost of serving System Losses that arise from an incremental Energy demand at the Elemental Pricing Node supplied by a loss adjusted Energy injection at the Reference Bus in the SCED-Pricing algorithm.

c. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at Aggregate Price Nodes.

The Transmission Provider shall calculate LMPs for each Hour and Aggregate Price Node in the Day-Ahead Energy and Operating Reserve Market. The calculation of LMPs for Aggregate Price Nodes will be based on the established normalized weighting factors for each Elemental Pricing Node defined in the Aggregate Price Node. The Aggregate Price Node LMP is equal to the sum of the products of the LMP at each Elemental Pricing Node and the associated normalized weighting factors for the Elemental Pricing Node.

d. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at Commercial Pricing Nodes.

The Transmission Provider shall establish relevant LMPs for each Hour and Commercial Pricing Node in the Day-Ahead Energy and Operating Reserve Market. The respective LMPs for Commercial Pricing Nodes, including the Marginal Congestion Component and Marginal Losses Component, shall be set equal to the respective LMP at the Elemental Pricing Node or Aggregate Price Node on which the Commercial Pricing Node is based.

e. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at a Resource Commercial Pricing Node.

The Transmission Provider shall determine the relevant LMP at a Resource Commercial Pricing Node as follows:

i. If the Resource has a single injection point and/or withdrawal point as in the case of an Electric Storage Resource, the relevant LMP for the Resource Commercial Pricing Node is set equal to the calculated respective LMP for the Elemental Pricing Node representing the Bus connected to the single injection or withdrawal point of the Resource.

ii. If the Resource has multiple injection points, that may or may not be connected to different Buses, the relevant LMP for the Resource Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Buses connected to each of the injection points of the Resource. The Aggregate Price Node weighing factors are specified by the Market Participant when the asset is registered.

f. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at a Load Zone Commercial Pricing Node

The Transmission Provider shall determine the relevant LMP for the Load Zone Commercial Pricing Node as follows:

i. If the Load Zone consists of a single Load, the relevant LMP for the Load Zone Commercial Pricing Node is set equal to the calculated respective LMP for the Elemental Pricing Node representing the Bus connected to the single Load.

ii. If the Load Zone consists of multiple Loads, the relevant LMP for the Load Zone Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Load Zone. The Aggregate Price Node representing the Load Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the Load Zone are connected.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the Load Zone's demand at the Elemental Pricing Node to the total demand of the Load Zone as determined by the results of the State Estimator from the average over the twenty-four (24) hours of seven (7) Days prior to the Operating Day.

g. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at a Hub Commercial Pricing Node

The Transmission Provider shall determine the relevant LMP for a Hub Commercial Pricing Node as follows:

i. If the Hub consists of a single Elemental Pricing Node, the relevant LMP for the Hub Commercial Pricing Node is set equal to the calculated respective LMP for the Elemental Pricing Node.

ii. If the Hub consists of multiple Elemental Pricing Nodes, the relevant LMP for the Hub Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Hub. The weighting factor for a specific Elemental Pricing Node is equal to a fixed normalized value determined by the Transmission Provider for the Hub, except as provided below for an ARR Zone administered as a Hub Commercial Pricing Node.

iii. Where an ARR Zone is administered as a Hub Commercial Pricing Node consisting of multiple Elemental Pricing Nodes, the relevant LMP for the Hub Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Hub. The Aggregate Price Node representing the ARR Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the ARR Zone are connected.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the ARR Zone's demand at the Elemental Pricing Node to the total demand of the ARR Zone as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operating Day.

h. Determination of Day-Ahead Ex Ante LMPs and Day-Ahead Ex Post LMPs at an Interface Commercial Pricing Node

The Transmission Provider shall determine the relevant LMP for an Interface Commercial Pricing Node as follows:

i. If the Interface consists of a single Elemental Pricing Node, the relevant LMP for the Interface Commercial Pricing Node is set equal to the calculated respective LMP for the Elemental Pricing Node.

ii. If the Interface consists of multiple Elemental Pricing Nodes, the relevant LMP for the Interface Commercial Pricing Node is set equal to the calculated respective LMP for the Aggregate Price Node representing the Interface. The weighting factor for a specific Elemental Pricing Node is equal to a normalized value determined by the Transmission Provider for the Interface.

i. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Regulating Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources and External Asynchronous Resources

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante and Ex Post Regulating Reserve MCP for Generation Resources, Demand Response Resources – Type II, , Electric Storage Resources, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Regulating Reserve Constraint Shadow Price, (iv) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (v) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost of managing the transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Regulating Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

j. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Spinning Reserve Market Clearing Price for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources and External Asynchronous Resources

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, , Electric Storage Resources and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (iv) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

k. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Spinning Reserve Market Clearing Price for Demand Response Resources – Type I.

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve for Demand Response Resources – Type I for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm respectively, if such Demand Response Resources – Type I are eligible to provide Spinning Reserve as determined by Applicable Reliability Standards. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Spinning Reserve for Demand Response Resources – Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

l. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Supplemental Reserve Market Clearing Price for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources and External Asynchronous Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve

Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

m. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Supplemental Reserve Market Clearing Price for Demand Response Resources - Type I

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve for Demand Response Resources - Type I for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Supplemental Reserve for Demand Response Resources - Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, and (ii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29 and Schedule 29A, respectively.

n. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Up Ramp Capability Market Clearing Price

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Up Ramp Capability for qualified Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante

MCPs and Day-Ahead Ex Post MCPs for a Resource for Up Ramp Capability is the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Requirement Constraint is as set forth in Schedule 29 and Schedule 29A, respectively.

o. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Down Ramp Capability Market Clearing Price

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Down Ramp Capability for qualified Resources for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Down Ramp Capability is the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint is as set forth in Schedule 29 and Schedule 29A, respectively.

p. Day-Ahead Ex Ante LMP, Day-Ahead Ex Post LMP, Day-Ahead Ex Ante MCP, and Day-Ahead Ex Post MCP Price Cap.

All Day-Ahead Ex Ante LMPs, Day-Ahead Ex Post LMPs, Day-Ahead Ex Ante MCPs, and Day-Ahead Ex Post MCPs will be capped at the Pricing VOLL.

q. Day-Ahead Offer Revenue Sufficiency Guarantee.

The Transmission Provider shall ensure the recovery of a Market Participant's Production Cost and Operating Reserve Cost for Resources committed by the Transmission Provider and scheduled in the Day-Ahead Energy and Operating Reserve Market, pursuant to Section 39.3.2B.

r. Determining the Day-Ahead Ex Ante and Day-Ahead Ex Post Short-Term Reserve Market Clearing Price.

On a day-ahead market basis, the Transmission Provider shall calculate the Day-Ahead Ex Ante MCPs and Day-Ahead Ex Post MCPs for Short-Term Reserve for qualified reserves for each Hour in the Day-Ahead Energy and Operating Reserve Market, using the SCED algorithm and SCED-Pricing algorithm, respectively. The Day-Ahead Ex Ante MCP and Day-Ahead Ex Post MCP for Short-Term Reserve are the applicable Cooptimized Zonal Short-Term Reserve Requirement constraint Shadow Prices.

If the sum of the fixed Demand Bids, Fixed Export Schedules, System Losses and Operating Reserve Requirements in the Day-Ahead Energy and Operating Reserve Market cannot be satisfied by the maximum non-Emergency supply level of all available non-Emergency Resources, Import Schedules and Virtual Supply Offers, the Transmission Provider shall clear the Day-Ahead Energy and Operating Reserve Market pursuant to the following procedures.

a. Step One. The Transmission Provider shall incorporate for use in the Day-Ahead Energy and Operating Reserve Market (i) the Market Participants' Offers submitted for each Generation Resource, Demand Response Resource – Type II, and External Asynchronous Resource up to the Hourly Emergency Maximum Limit, and up to the Hourly Emergency Maximum Discharge Limit and Hourly Emergency Minimum Energy Storage Level, except for Resources selected to provide Regulating Reserve, and (ii) the commitment of Generation Resources, Demand Response Resources - Type I, and Demand Response Resources - Type II that are designated as available for Emergency conditions only, and the commitment of Electric Storage Resources with a Commitment Status of Emergency Discharge, in amounts required to relieve the shortage condition in an economic manner. Day-Ahead Schedules, Ex Ante LMPs, and Ex Ante MCPs are then determined using the SCED algorithm. Ex Post LMPs and Ex Post MCPs are then determined using the SCED-Pricing algorithm, where Proxy Offers will be used as specified in Schedule 29A. Both SCED and SCED-Pricing algorithms will include Scarcity Pricing based on the Operating Reserve Demand Curves, Regulating and Spinning Reserve Demand Curves, and Regulating

Reserve Demand Curves if Operating Reserve is insufficient to meet the Market-Wide Operating Reserve Requirement following the release of Emergency Capacity described under (i) and (ii) above. Both SCED and SCED-Pricing algorithms will include Scarcity Prices based on the Market-Wide Short-Term Reserve Demand Curve if Short-Term Reserve is insufficient to meet the Market-Wide Short-Term Reserve Requirement following the release of Emergency Capacity described under (i) and (ii) above.

b. Step Two. If Operating Reserve is depleted and the Energy balance cannot be achieved after the process described in Step One above has been implemented, the Transmission Provider will curtail Fixed Demand Bids and Fixed Export Schedules in proportion to the scheduled amounts. Under this situation, all Energy and Operating Reserve will be priced at the Pricing VOLL.

The Transmission Provider shall (i) use a SCED algorithm to clear Offers, Self-Schedules, and Interchange Schedules, (ii) determine the MISO Balancing Authority NSI, and (iii) establish prices and physically binding Dispatch Targets for each Resource and Dispatch Interval.

a. Determination of Dispatch Targets

In the Real-Time Energy and Operating Reserve Market, the Transmission Provider shall determine Dispatch Targets for Energy, Regulating Reserve, Spinning Reserve, Supplemental Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve for each Resource for the end of each Dispatch Interval.

b. Determination of the Real-Time Ex Ante LMPs at Elemental Pricing Nodes

The Transmission Provider shall calculate Real-Time Ex Ante LMPs for each Dispatch Interval and Elemental Pricing Node in the Real-Time Energy and Operating Reserve Market using the SCED algorithm. The Real-Time Ex Ante LMP at an Elemental Pricing Node in a specific Dispatch Interval is the marginal Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve and, if applicable, Reserve Scarcity costs, Up Ramp Capability scarcity costs, Down Ramp Capability scarcity costs, and/or Short-Term Reserve scarcity costs to supply Energy to a Load at the Elemental Pricing Node during the Dispatch Interval using the SCED algorithm. The Real-Time Ex Ante LMPs are established based on (i) Generation Offers, (ii) Demand Response Resource – Type II Offers, (iii) Electric Storage Resource Offers, and (iv) External Asynchronous Resource Offers.

i. Calculation of Marginal Congestion Component. The Transmission Provider will calculate the Cost of Congestion at each Elemental Pricing Node as a component of the Real-Time Ex Ante LMP (the Marginal Congestion Component).

The Marginal Congestion Component of a Real-Time Ex Ante LMP reflects the marginal cost of managing the transmission congestion and enforcing Sub-Regional Power Balance Constraints that will arise from an incremental Energy demand at the Elemental Pricing Node supplied by an incremental Energy injection at the Reference Bus in the SCED algorithm.

ii. Calculation of Marginal Losses Component. The Transmission Provider will calculate the Cost of Losses at each Elemental Pricing Node as a component of the Real-Time Ex Ante LMP at that Elemental Pricing Node (the Marginal Losses Component). The Marginal Losses Component of a Real-Time Ex Ante LMP reflects the marginal cost of serving System Losses that arise from an incremental Energy demand at the Elemental Pricing Node supplied by a loss adjusted Energy Injection at the Reference Bus in the SCED algorithm.

c. Determination of the Real-Time Ex Ante LMPs at Aggregate Price Nodes.

The Transmission Provider shall calculate Real-Time Ex Ante LMPs for each Dispatch Interval and Aggregate Price Node in the Real-Time Energy and Operating Reserve Market. The calculation of Real-Time Ex Ante LMPs for Aggregate Price Nodes will be based on established normalized weighting factors for each Elemental Pricing Node defined in the Aggregate Price Node. The Aggregate Price Nodes LMP is equal to the sum the products of the Real-Time Ex Ante LMP at each Elemental Pricing Node and the associated weighting factor for the Elemental Pricing Node.

d. Determination of the Real-Time Ex Ante LMPs at Commercial Pricing Nodes.

The Transmission Provider shall establish Real-Time Ex Ante LMPs for each Dispatch Interval and Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market. The Real-Time Ex Ante LMPs for Commercial Pricing Nodes, including the Marginal Congestion Component and Marginal Losses Component, shall be set equal to the Real-Time Ex Ante LMP at the Elemental Pricing Node or Aggregate Price Node on which the Commercial Pricing Node is based.

e. Determination of the Real-Time Ex Ante LMP at a Resource Commercial Pricing Node.

The Transmission Provider shall determine the Real-Time Ex Ante LMP at a Resource Commercial Pricing Node as follows:

i. If the Resource has a single injection point, the Real-Time Ex Ante LMP for the Resource Commercial Pricing Node is set equal to the calculated Ex Ante LMP for the Elemental Pricing Node representing the Bus connected to the single injection point of the Resource.

ii. If the Resource has multiple injection points, that may or may not be connected to different Buses, the Real-Time Ex Ante LMP for the Resource Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Buses connected to each of the injection points of the Resource. The Aggregate Price Node weighting factors are specified by the Market Participant when the asset is registered.

f. Determination of the Real-Time Ex Ante LMP at a Load Zone Commercial Pricing Node

The Transmission Provider shall determine the Real-Time Ex Ante LMP for the Load Zone Commercial Pricing Node as follows:

i. If the Load Zone consists of a single Load, the Real-Time Ex Ante LMP for the Load Zone Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Elemental Pricing Node representing the Bus connected to the single Load.

ii. If the Load Zone consists of multiple Loads, the Real-Time Ex Ante LMP for the Load Zone Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Load Zone.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the Load Zone's demand at the Elemental Pricing Node to the total Demand of the Load Zone, as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operation Day.

g. Determination of the Real-Time Ex Ante LMP at a Hub Commercial Pricing Node

The Transmission Provider shall determine Real-Time Ex Ante LMP for a Hub Commercial Pricing Node as follows:

i. If the Hub consists of a single Elemental Pricing Node, the Real-Time Ex Ante LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Elemental Pricing Node.

ii. If the Hub consists of multiple Elemental Pricing Nodes, the Real-Time Ex Ante LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Hub. The weighting factor for a specific Elemental Pricing Node is equal to a fixed normalized value determined by the Transmission Provider for the Hub, except as provided below for an ARR Zone administered as a Hub Commercial Pricing Node.

iii. Where an ARR Zone is administered as a Hub Commercial Pricing Node consisting of multiple Elemental Pricing Nodes, the Real-Time Ex Ante LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Hub. The Aggregate Price Node representing the ARR Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the ARR Zone are connected.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the ARR Zone's demand at the Elemental Pricing Node to the total demand of the ARR Zone, as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operating Day.

h. Determination of the Real-Time Ex Ante LMP at an Interface Commercial Pricing Node

The Transmission Provider shall determine Real-Time Ex Ante LMP for an Interface Commercial Pricing Node as follows:

i. If the Interface consists of a single Elemental Pricing Node, the Real-Time Ex Ante LMP for the Interface Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Elemental Pricing Node.

ii. If the Interface consists of multiple Elemental Pricing Nodes, the Real-Time Ex Ante LMP for the Interface Commercial Pricing Node is set equal to the calculated Real-Time Ex Ante LMP for the Aggregate Price Node representing the Interface.

i. Determining the Real-Time Ex Ante Regulating Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources is equal to the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Regulating Reserve Constraint Shadow Price, (iv) Market-Wide Non-DRR1 Operating Reserve Constraint

Shadow Price, (v) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost for managing congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Regulating Reserve from the Reference Bus to the Reserve Zone; all such Constraints noted herein are as set forth in Schedule 29.

j. Determining the Real-Time Ex Ante Spinning Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (iv) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost for managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29. Such Spinning Reserved MCPs for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources shall be calculated on a real-time basis for each Dispatch Interval of the Real-Time Energy and Operating Reserve Market.

k. Determining the Ex Ante Spinning Reserve Market Clearing Price for Demand Response Resources – Type I

The Transmission Provider shall calculate the Ex Ante Spinning Reserve MCPs for Demand Response Resources – Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED algorithm, if such Demand Response Resources – Type I are eligible to provide Spinning Reserve as determined by Applicable Reliability Standards. The Spinning Reserve MCP for Demand Response Resources –Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29.

l. Determining the Real-Time Ex Ante Supplemental Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources is the sum of the (i) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (ii) Market-Wide Generation-based Operating Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29.

m. Determining the Real-Time Ex Ante Supplemental Reserve Market Clearing Price for Demand Response Resources - Type I

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Supplemental Reserve for Demand Response Resources - Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Supplemental Reserve for Demand Response Resources - Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, and (ii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29.

n. Determining the Ex Ante Up Ramp Capability Market Clearing Price

The Transmission Provider shall calculate the Real-Time Ex Ante Up Ramp Capability MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED algorithm. The Real-Time Ex Ante Up Ramp Capability MCP for a Resource is the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Constraint is as set forth in Schedule 29. Such Up Ramp Capability MCPs for Resources shall be calculated on a real-time basis for each Dispatch Interval of the Real-Time Energy and Operating Reserve Market.

o. Determining the Ex Ante Down Ramp Capability Market Clearing Price

The Transmission Provider shall calculate the Real-Time Ex Ante Down Ramp Capability MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED algorithm. The Real-Time Ex Ante Down Ramp Capability MCP for a Resource is the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Constraint is as set forth in Schedule 29. Such Down Ramp Capability MCPs for Resources shall be calculated on a real-time basis for each Dispatch Interval of the Real-Time Energy and Operating Reserve Market.

p. Real-Time Ex Ante LMP and Real-Time Ex Ante MCP Price Cap.

All Real-Time Ex Ante LMPs and Real-Time Ex Ante MCPs will be capped at the Pricing VOLL.

q. Determining the Ex Ante Regulating Mileage Market Clearing Price

The Transmission Provider shall calculate the Ex Ante Regulating Mileage MCPs for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market. The Ex Ante Regulating Mileage MCP for a Dispatch Interval is the highest Regulating Mileage Offer among all Resources that meet the following criteria: (1) if the Resource has a Day-Ahead schedule for cleared Regulating Reserve, then the Regulating Reserve Dispatch Status in the Day-Ahead Energy and Operating Reserve Market must be economic, (2) the Regulating Reserve Dispatch Status has to be economic in the Real-Time Energy and Operating Reserve Market, and (3)the Resource has a non-zero Dispatch Target for Regulating Reserve in that Dispatch Interval.

r. Determining the Real-Time Ex Ante Short-Term Reserve Market Clearing Price

The Transmission Provider shall calculate the Real-Time Ex Ante MCPs for Short-Term Reserve for qualified reserves for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED algorithm. The Real-Time Ex Ante MCP for Short-Term Reserve is the applicable Co-optimized Zonal Short-Term Reserve Requirement constraint Shadow Price.

For each Dispatch Interval, the Transmission Provider shall use the SCED-Pricing algorithm to establish Real-Time Ex Post LMPs and Real-Time Ex Post MCPs. The Real-Time Ex Post LMPs and Real-Time Ex Post MCPs will be subject to input data validation and adherence to the price calculation requirements. Input data validation corrections will be made pursuant to Section 40.2.18 of this Tariff. The Real-Time Ex Post LMPs and Real-Time Ex Post MCPs are used to settle Real-Time Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and Short-Term Reserve deviations and are determined as described below:

a. Determination of the Real-Time Ex Post LMPs at Elemental Pricing Nodes

The Transmission Provider shall calculate Real-Time Ex Post LMPs for each Dispatch Interval and Elemental Pricing Node in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post LMP at an Elemental Pricing Node in a specific Dispatch Interval is the marginal Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve and, if applicable, Reserve Scarcity costs, Up Ramp Capability scarcity costs, Down Ramp Capability scarcity costs, and/or Short-Term Reserve scarcity costs to supply Energy to Load at the Elemental Pricing Node during the Dispatch Interval using the SCED-Pricing algorithm, described in Schedule 29A. The Real-Time Ex Post LMPs are established based on (i) Generation Offers, (ii) Demand Response Resource Offers, (iii) External Asynchronous Resource Offers, (iv) Emergency Demand Response resource Offers; (v) Electric Storage Resource Offers; and (vi) Proxy Offers when appropriate as specified in Schedule 29A.

i. Calculation of Marginal Congestion Component. The Transmission Provider will calculate the Cost of Congestion at each Elemental Pricing Node as a component of the Real-Time Ex Post LMP (the Marginal Congestion Component). The Marginal Congestion Component of a Real-Time Ex Post LMP reflects the marginal cost of managing the transmission congestion and enforcing Sub-Regional Power Balance Constraints that will arise from an incremental Energy demand at the Elemental Pricing Node supplied by an incremental Energy injection at the Reference Bus.

ii. Calculation of Marginal Losses Component. The Transmission Provider will calculate the Cost of Losses at each Elemental Pricing Node as a component of the Real-Time Ex Post LMP at that Elemental Pricing Node (the Marginal Losses Component). The Marginal Losses Component of any Real-Time Ex Post LMP reflects the marginal cost of serving System Losses that arise from an incremental Energy demand at the Elemental Pricing Node supplied by a loss adjusted Energy Injection at the Reference Bus.

b. Determination of Real-Time Ex Post LMPs at Aggregate Price Nodes.

The Transmission Provider shall calculate Real-Time Ex Post LMPs for each Dispatch Interval and Aggregate Price Node in the Real-Time Energy and Operating Reserve Market. The calculation of Real-Time Ex Post LMPs for Aggregate Price Nodes will be based on established normalized weighting factors for each Elemental Pricing Node defined in the Aggregate Price Node. The Aggregate Price Node is equal to the sum of the products of the Real-Time Ex Post LMP at each Elemental Pricing Node and the associated weighting factor for the Elemental Pricing Node.

c. Determination of the Real-Time Ex Post LMPs at Commercial Pricing Nodes

The Transmission Provider shall establish Real-Time Ex Post LMPs for each Dispatch Interval and Commercial Pricing Node in the Real-Time Energy and Operating Reserve Market. The Real-Time Ex Post LMPs for Commercial Pricing Nodes, including the Marginal Congestion Component and Marginal Losses Component, shall be set equal to the Real-Time Ex Post LMP at the Elemental Pricing Node or Aggregate Price Node on which the Commercial Pricing Node is based.

d. Determination of the Real-Time Ex Post LMP at a Resource Commercial Pricing Node.

The Transmission Provider shall determine the Real-Time Ex Post LMP at a Resource Commercial Pricing Node as follows:

i. If the Resource has a single injection and/or withdrawal point, the Real-Time Ex Post LMP for the Resource Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Elemental Pricing Node representing the Bus connected to the single injection and/or withdrawal point of the Resource.

ii. If the Resource has multiple injection points, that may or may not be connected to different Buses, the Real-Time Ex Post LMP for the Resource Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Buses connected to each of the injection points of the Resource.

The Aggregate Price Node weighing factors are specified by the Market Participant when the asset is registered.

e. Determination of the Real-Time Ex Post LMP at a Load Zone Commercial Pricing Node

The Transmission Provider shall determine an Real-Time Ex Post LMP for the Load Zone Commercial Pricing Node as follows:

i. If the Load Zone consists of a single Load, the Real-Time Ex Post LMP for the Load Zone Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Elemental Pricing Node representing the Bus connected to the single Load.

ii. If the Load Zone consists of multiple Loads, the Real-Time Ex Post LMP for the Load Zone Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Load Zone. The Aggregate Price Node representing the Load Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the Load Zone are connected. The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the Load Zone's demand at the Elemental Pricing Node to the total demand of the Load Zone as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operation Day.

f. Determination of the Real-Time Ex Post LMP at a Hub Commercial Pricing Node

The Transmission Provider shall determine Real-Time Ex Post LMP for a Hub Commercial Pricing Node as follows:

i. If the Hub consists of a single Elemental Pricing Node, the Real-Time Ex Post LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Elemental Pricing Node.

ii. If the Hub consists of multiple Elemental Pricing Nodes, the Real-Time Ex Post LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Hub. The weighting factor for a specific Elemental Pricing Node is equal to a fixed normalized value determined by the Transmission Provider for the Hub, except as provided below for an ARR Zone administered as a Hub Commercial Pricing Node.

iii. Where an ARR Zone is administered as a Hub Commercial Pricing Node consisting of multiple Elemental Pricing Nodes, the Real-Time Ex Post LMP for the Hub Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Hub. The Aggregate Price Node representing the ARR Zone is comprised of Elemental Pricing Nodes representing the Buses where the individual Loads that comprise the ARR Zone are connected.

The weighting factor for a specific Elemental Pricing Node is equal to the ratio of the ARR Zone's demand at the Elemental Pricing Node to the total demand of the ARR Zone, as determined by the results of the State Estimator solution from the average over the twenty-four (24) hours of seven (7) Days prior to the Operating Day.

g. Determination of the Real-Time Ex Post LMP at an Interface Commercial Pricing Node

The Transmission Provider shall determine Real-Time Ex Post LMP for an Interface Commercial Pricing Node as follows:

i. If the Interface consists of a single external Elemental Pricing Node, the Real-Time Ex Post LMP for the Interface Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Elemental Pricing Node.

ii. If the Interface consists of multiple external Elemental Pricing Nodes, the Real-Time Ex Post LMP for the Interface Commercial Pricing Node is set equal to the calculated Real-Time Ex Post LMP for the Aggregate Price Node representing the Interface. The weighting factor for a specific Elemental Pricing Node is equal to a normalized value determined by the Transmission Provider for the Interface.

h. Determining the Real-Time Ex Post Regulating Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post MCPs for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Regulating Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources is equal to the sum of the (i) Market-

Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Regulating Reserve Constraint Shadow Price, (iv) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (v) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning Reserve Constraint Shadow Price, and (vi) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Regulating Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

i. Determining the Real-Time Ex Post Spinning Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post MCPs for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Spinning Reserve for Generation Resources, Demand Response Resources – Type II, and External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Regulating and Spinning Reserve Constraint Shadow Price, (iii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, (iv) Market-Wide Non-Demand Response Resource – Type I Regulating and Spinning

Reserve Constraint Shadow Price, and (v) beginning November 1, 2011, additional marginal cost for managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

j. Determining the Real-Time Ex Post Spinning Reserve Market Clearing Prices for Demand Response Resources- Type I

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post MCPs for Spinning Reserve for Demand Response Resources – Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market if such Demand Response Resources – Type I are eligible to provide Spinning Reserve as determined by Applicable Reliability Standards. The Real-Time Ex Post MCP for Spinning Reserve for Demand Response Resources –Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market- Wide Regulating and Spinning Reserve Constraint Shadow Price, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Spinning Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

k. Determining the Real-Time Ex Post Supplemental Reserve Market Clearing Prices for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources

The Transmission Provider shall calculate the Real-Time Ex Post MCPs for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, and External Asynchronous Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Supplemental Reserve for Generation Resources, Demand Response Resources – Type II, Electric Storage Resources, or External Asynchronous Resources is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, (ii) Market-Wide Non-DRR1 Operating Reserve Constraint Shadow Price, if applicable, and (iii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

l. Determining the Real-Time Ex Post Supplemental Reserve Market Clearing Prices for Demand Response Resources - Type I

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post MCPs for Supplemental Reserve for Demand Response Resources - Type I for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market using the SCED-Pricing algorithm. The Real-Time Ex Post MCP for Supplemental Reserve for Demand Response Resources - Type I is the sum of the (i) Market-Wide Operating Reserve Constraint Shadow Price, and (ii) beginning November 1, 2011, additional marginal cost of managing transmission congestion, and beginning August 26, 2018, additional marginal cost of enforcing Sub-Regional Power Balance Constraints, in order to supply incremental Supplemental Reserve from the Reference Bus to the Reserve Zone. All such constraints noted herein are as set forth in Schedule 29A.

m. Determining the Real-Time Ex Post Up Ramp Capability Market Clearing Prices

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post Up Ramp Capability MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, using the SCED-Pricing algorithm. The Real-Time Ex Post Up Ramp Capability MCP for a Resource is the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Up Ramp Capability Constraint is as set forth in Schedule 29A.

n. Determining the Real-Time Ex Post Down Ramp Capability Market Clearing Prices

On a real-time market basis, the Transmission Provider shall calculate the Real-Time Ex Post Down Ramp Capability MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED-Pricing algorithm. The Real-Time Ex Post Down Ramp Capability MCP for a Resource is the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Requirement Constraint Shadow Price where the Ramp Procurement Minimum Reserve Zone Down Ramp Capability Constraint is as set forth in Schedule 29A.

o. Real-Time Ex Post LMP and Real-Time Ex Post MCP Price Cap. All Real-Time Ex Post LMPs and Real-Time Ex Post MCPs will be capped at the Pricing VOLL.

p. Determining the Ex Post Regulating Mileage Market Clearing Price

The Transmission Provider shall calculate the Ex Post Regulating Mileage MCPs for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market. The Ex Post Regulating Mileage MCP is the highest Regulating Mileage Offer among all Resources that meet the following criteria: (1) if the Resource has a Day-Ahead Schedule for cleared Regulating Reserve, then the Regulating Reserve Dispatch Status in the Day-Ahead Energy and Operating Reserve Market must be economic, (2) the Regulating Reserve Dispatch Status has to be economic in the Real-Time Energy and Operating Reserve Market, and (3) the Resource has a non-zero Dispatch Target for Regulating Reserve in that Dispatch Interval. The Ex Post Regulating Mileage MCP is used to settle Additional Regulating Mileage in that Dispatch Interval.

q. Determining the Real-Time Ex Post Short-Term Reserve Market Clearing Prices

On a real-time market basis, the Transmission Provider shall calculate the real-time Ex Post Short-Term reserve MCPs for qualified Resources for each Dispatch Interval in the Real-Time Energy and Operating Reserve Market, based on the SCED-Pricing algorithm. The real-time Ex Post Short-Term Reserve MCP for a Resource is the applicable Co-optimized Zonal Short-Term Reserve Requirement constraint Shadow Price.

Capacity Shortage Conditions in the Real-Time Energy and Operating Reserve Market:

The Transmission Provider shall take the measures set forth below during Capacity shortage conditions to maintain reliability within the MISO Balancing Authority Area.

a. RAC

If during any RAC process, the Transmission Provider's forecast of Real-Time demand and Operating Reserve Requirements, either on a MISO Balancing Authority Area basis or Sub-Area basis, cannot be satisfied by committing all available non-Emergency Capacity, up to Hourly Economic Maximum Limits, up to the Hourly Economic Maximum Discharge Limits and Hourly Minimum Energy Storage Levels for Electric Storage Resources, and the Forecast Maximum Limit for Dispatchable Intermittent Resources, the Transmission Provider shall implement the following procedures:

i. Step One. The Transmission Provider shall: incorporate for use in the RAC commitment process, the order of which is specified in the Transmission Provider's Emergency operating procedures: (i) the Market Participants' Offers submitted for each Generation Resource, Demand Response Resource - Type II, External Asynchronous Resource, and Hourly Emergency Minimum Energy Storage Level or Hourly Emergency Maximum Discharge Limit for an Electric Storage Resource, or the Forecast Maximum Limit for Dispatchable Intermittent Resources, except for Resources selected to provide Regulating Reserve, (ii) the commitment of Generation Resources, Demand Response Resources - Type I, and Demand Response Resources - Type II that are designated as available for Emergency conditions only, and the commitment of Electric Storage Resources with a Commitment Status of Emergency Discharge, (iii) the curtailment of Export Schedules, in amounts required to relieve the shortage condition in an economic manner; and (iv) the schedules of External Resources that qualified as Planning Resources.

ii. Step Two. If the action under Step One above is not sufficient to relieve the anticipated shortage condition, the Transmission Provider shall declare an EEA-Level 1. In the event that a significant shortage of Operating Reserve is anticipated, the Transmission Provider shall declare an EEA-Level 2 and shall mitigate, but not necessarily eliminate, the Operating Reserve deficiency through use of the following options, the order of which is specified in the Transmission Provider's Emergency operating procedures: (a) Issuing EDR Dispatch Instructions to EDR Participants based upon EDR Offers submitted (b) initiating Emergency Energy purchases in accordance with the procedures set forth in Section 40.2.22, (c) issuing public appeals to reduce demand as appropriate, (d) directing Local Balancing Authorities to implement voltage reductions, and (e) directing Load Serving Entities to curtail appropriate amounts of Load Modifying Resources.

b. Real-Time Dispatch Interval

During any SCED Dispatch Interval for which the Transmission Provider has previously issued an EEA-Level 1 or EEA-Level 2, the Transmission Provider shall implement the following procedures to clear the Real-Time Energy and Operating Reserve Market:

i. For those Resources selected to operate above the Hourly Economic Maximum Limits and Hourly Economic Maximum Discharge Limits and down to the Hourly Minimum Energy Storage Level during the RAC process pursuant to Section 40.2.20.a.i., the Transmission Provider shall use the Market Participant's Offers for such Resources up to the Hourly Emergency Maximum Limit and Hourly Emergency Maximum Discharge Limit and down to the Hourly Minimum Energy Storage Level in the SCED to calculate Real-Time Ex Ante LMPs and Real-Time Ex Ante MCPs, and shall use the Resource's Proxy Offers specified in Schedule 29A in the SCED-Pricing to calculate Real-Time Ex Post LMPs and Real-Time Ex Post MCPs which will reflect Scarcity Pricing based upon Demand Curves, if sufficient Operating Reserve is not cleared to meet the Market-Wide Operating Reserve Requirement, if sufficient Up Ramp Capability is not cleared to meet the Market-Wide Up Ramp Capability Requirement, and/or if sufficient Short-Term Reserve is not cleared to meet the Market-Wide Short-Term Reserve Requirement. For scheduled External Resources that qualified as Planning Resources, the Transmission Provider shall also use their Proxy Offers specified in Schedule 29A in the SCED-Pricing to calculate Real-Time Ex Post LMPs and Real-Time Ex Post MCPs.

ii. For Load Modifying Resources, Emergency Demand Response resources and Emergency Energy Purchases selected to operate during the RAC process pursuant to Section 40.2.20.a.ii, the Transmission Provider shall use their Proxy

Offers specified in Schedule 29A in the SCED-Pricing to calculate Real-Time Ex Post LMPs and Real-Time Ex Post MCPs

iii. If as a result of the Transmission Provider actions pursuant to Section 40.2.20.b.i, Energy balance cannot be achieved, the Transmission Provider shall declare an EEA-Level 3 and may implement Load Shedding pursuant to the Transmission Provider's Emergency operating procedures. Load Shedding will be implemented on a MISO Balancing Authority Area basis, or a on a Sub-Area basis if limited by transmission constraints or Sub-regional Power Balance Constraints, as required to restore Energy balance. The Load Shedding obligation of each Load Serving Entity shall be implemented through instructions to the affected Local Balancing Authorities as set forth in the protocols of the Balancing Authority Agreement. Load Shedding shall be allocated to each affected Local Balancing Authority on a pro rata, Load Ratio Share basis, determined by the ratio of the total amount of Load Shedding required to achieve Energy balance to the amount of the real-time load remaining, or if the Load Shedding is to occur in the next hour, to the projected load for the next-hour, for the Sub-Area or the entire MISO Balancing Authority Area, as applicable. During Emergency conditions where Load Shedding is instructed by the Transmission Provider when the affected area is the MISO Balancing Authority Area or Sub-Area, Real-Time Ex Ante LMPs, Real-Time Ex Ante MCPs, Real-Time Ex Post LMPs and Real-Time Ex Post Operating Reserve MCPs will be set to the Pricing VOLL, either on a MISO

Balancing Authority Area basis or Sub-Area basis, as applicable, until the Emergency condition is no longer in effect.

iv. When an EEA-Level 3 declared by the Transmission Provider pursuant to Section 40.2.20.b.iii satisfies any of the following conditions, the Pricing VOLL shall be adjusted as follows:

(1) Once the cumulative duration of the EEA-Level 3 reaches four (4) hours, the Real-Time Energy and Operating Reserve Market Pricing VOLL as set forth in Sections 40.2.15.p and 40.2.17.o shall be reduced to $5,000/MWh. The cumulative EEA-Level 3 duration is paused when the EEA-Level 3 is exited, but Capacity shortage conditions remain, as declared by the Transmission Provider. The cumulative EEA-Level 3 duration is deemed ended when the Transmission Provider declares an end to Capacity shortage conditions.

(2) If at the time of the close of the Day-Ahead Energy and Operating Reserve Market, the Capacity shortage that led to the declaration of the EEA-Level 3 is continuing, the Pricing VOLL shall be reduced to $5,000/MWh. This Pricing VOLL is applied on the next Operating Day for both the Day-Ahead Energy and Operating Reserve Market (Sections 39.2.9.p and 39.2.10.b) and the Real-Time Energy and Operating Reserve Market (Sections 40.2.15.p and 40.2.17.o).

(3) If the Capacity shortage conditions described in sub-paragraph (2) persist at the time of the close of any additional Day-Ahead Energy and

Operating Reserve Market(s), the Pricing VOLL shall be further reduced to $2,000/MWh for both the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market for the next Operating Day(s).

(4) After conditions described in sub-paragraphs (1), (2) and/or (3) have ended and the Transmission Provider declares an end to Capacity shortage conditions, the Pricing VOLL shall be reset to the initial value of $10,000/MWh, depending on applicable conditions in sub-parts a and b below:

a. At the end of the current Operating Day, if the Transmission Provider declares an end to the Capacity shortage conditions before the close of the Day-Ahead Energy and Operating Reserve Market.

b. At the end of the next Operating Day, if the Transmission Provider declares an end to the Capacity shortage conditions after the close of the Day-Ahead Energy and Operating Reserve Market.

c. Notice

The Transmission Provider shall post on its public website notice of the existence and duration of the conditions requiring the implementation of the procedures set forth in this Section 40.2.20.

SCHEDULE 28

Demand Curves for Operating Reserve, Regulating and Spinning Reserve, and Regulating Reserve, Up Ramp Capability, Down Ramp Capability, and Market-Wide Short-Term Reserve

I. INTRODUCTION

Demand Curves shall be used by the Transmission Provider to determine the incremental value of Market-Wide Operating Reserve, Market-Wide Regulating and Spinning Reserve, Market-Wide Regulating Reserve, Market-Wide Up Ramp Capability, Market-Wide Down Ramp Capability, and Market-Wide Short-Term Reserve to Load Serving Entities and, if applicable, Market Participants with Exports. Demand Curves shall be used in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets.

II. GENERAL

The Reserve Demand Curves shall be developed to price Operating Reserve when sufficient Operating Reserves, Regulating and Spinning Reserves, or sufficient Regulating Reserves are not cleared to meet the corresponding Operating Reserve, Regulating and Spinning Reserve, or Regulating Reserve requirement. The Up Ramp Capability Demand Curve shall be developed to price Up Ramp Capability when sufficient Up Ramp Capability is not cleared to meet the Market-Wide Up Ramp Capability Requirement. The Down Ramp Capability Demand Curve shall be developed to price Down Ramp Capability when sufficient Down Ramp Capability is not cleared to meet the Market-Wide Down Ramp Capability Requirement. The Market-Wide Short-Term Reserve Demand Curve shall be developed to price Short-Term Reserve when sufficient Short-Term Reserve is not cleared to meet the Market-Wide Short-Term Reserve Requirement.

III. MARKET-WIDE OPERATING RESERVE DEMAND CURVE

When the cleared Operating Reserve level is less than the Market-Wide Operating Reserve Requirement, the Operating Reserve price is determined using a Market-Wide Operating Reserve Demand Curve. The price is related to the amount of Operating Reserve cleared relative to the Operating Reserve Requirement, determined as follows:

i. If the cleared level of Operating Reserve is less than the minimum of 100%, or the percentage amount required to satisfy the Most Severe Single Contingency, as defined by NERC, and as determined by the Reserve Sharing Group, times the Operating Reserve Requirement, the price is the product of (i) the System VOLL and (ii) the Loss of Load Probability Curve. This price has maximum and minimum limits. The maximum price is $6,000/MWh. The minimum price is $1,100/MWh (sum of the lower bound of the Emergency Tier II Offer Floor, $1,000 and the Contingency Reserve Offer Price Cap, $100).

ii. If the cleared level of Operating Reserve is less than 100% of the Operating Reserve Requirement, but greater than or equal to the percentage amount required to satisfy the Most Severe Single Contingency, as defined by NERC, and as determined by the Reserve Sharing Group, the price is $600/MWh (sum of the lower bound of the Emergency Tier I Offer Floor, $500 and the Contingency Reserve Offer Cap, $100). This provision will not apply when the percentage amount required to satisfy the Most Severe Single Contingency, as defined by NERC, and as determined by the Reserve Sharing Group is greater than or equal to 100% of the requirement level.

IV. MARKET-WIDE REGULATING RESERVE DEMAND CURVE

Availability of Regulating Reserves depends both upon the Resources that are committed and on how the committed Resources are dispatched. When the Transmission Provider is not able to meet the Market Wide Regulating Reserve Requirement using committed Resources, it can take actions such as changing the commitment of Resources to make Capacity available to meet Regulating Reserve Requirements. For cleared Market-Wide Regulating Reserve levels less than the Market-Wide Regulating Reserve Requirement, the Market-Wide Regulating Reserve Demand Curve price will be set based upon the greater of (i) the Contingency Reserve Offer Cap or (ii) the average cost per MWh of committing and running a peaking unit for an hour.

The Market-Wide Regulating Reserve Demand Curve price shall be established monthly and posted on the Transmission Provider's website seven (7) days prior to the beginning of the month for which it will be effective. The average cost per MWh of committing and running a peaking unit for an hour shall be calculated based upon:

(a) A spot gas price index in $/MMBtu, which will be specified, and amended when necessary, in the Transmission Provider's Business Practices Manuals or other documentation on the Transmission Provider's website. Prior to each month, the average of the spot gas price index over the first three weeks of the month prior to the month for which the Market-Wide Regulating Reserve Demand Curve price is being calculated will be calculated.

(b) An annual proxy heat rate determined once a year by the Transmission Provider as the mean of the single hour Offer prices of peakers offered in the Day Ahead and Real-Time Markets over the past year, as specified in (c) through (f) below. The product of the monthly average spot gas price from (a) and the annual proxy heat rate from (b) will be the Market Wide Regulating Reserve Demand Curve Price for each Hour for cleared Market Wide Regulating Reserve levels less than the Market Wide Regulating Reserve Requirement.

(c) AnnualProxyHeatRate is an effective heat rate based on the peaker Offers submitted each day and the spot gas prices for that day for each of the days in the year (to the date of calculation). This value will be expressed as MMBtu/MWh and will be calculated annually as follows:

$$\text{Annual Proxy Heat Rate} = \frac{\left(\sum_{o}\sum_{d} \text{Average Daily Proxy Heat Rate}_{o,\,d}\right)}{\text{Offer Count}}$$

where:

"o" is an index of the Day-Ahead and Real-Time Market peaker Offers in a day;

"d" is an index of the days in the year to the date of calculation, and

"Offer Count" is the total number of Offers by peakers in the Day-Ahead and Real-Time Markets over the year to the date of calculation.

The average daily proxy heat rate for each Offer o on each day d, $\text{AverageDailyProxyHeatRate}_{o,d}$, will be calculated as

$$\frac{\sum_{h} \left(\text{AIE Cost}_{o,\,d,\,h} + \text{ASU Cost}_{o,\,d,\,h} + \text{ANL Cost}_{o,\,d,\,h}\right)}{\text{Number Hours} \times \text{Spot Gas Price}_{d}}$$

where:

"d" indexes the day;

"h" indexes the hours of the day d;

"NumberHours" is the number of hours for Offer o on day d;

$SpotGasPrice_{d}$ is the spot gas price on day d as given in the index specified in (a);

$AIECost_{o,d,h}$ is the average Incremental Energy Price in $/MWh for Offer o on day d in Hour h as defined in (d) below;

$ASUCost_{o,d,h}$ is the average start-up cost in $/MWh for Offer o on day d in Hour h as defined in (e) below; and

$ANLCost_{o,d,h}$ is the average no-load cost in $/MWh for Offer o on day d in Hour h as defined in (f) below.

(d) $AIECost_{o,d,h}$ is defined as

$$\frac{\int_{0}^{EconMax_{o,d,h}} IEOffer\ Curve_{o,d,h}(x)dx}{EconMax_{o,d,h}}$$

where:

$IEOfferCurve_{o,d,h}(x)$ is the Incremental Energy Price curve in Offer o on day d in Hour h;

$EcoMax_{o,d,h}$ is the economic maximum output for Offer o on day d in Hour h.

(e) $ASUCost_{o,d,h}$ is defined as

$\underline{SUOffer_{o,d,h}}$

$EconMax_{o, d, h}$

where:

$SUOffer_{o,d,h}$ is the cold Start-Up Offer price in Offer o on day d in Hour h.

(f) $ANLCost_{o,d,h}$ is defined as

$\underline{NLOffer_{o, d, h}}$

$EconMax_{o, d, h}$

where:

$NLOffer_{o,d,h}$ is the No-Load Offer price in Offer o on day d in Hour h.

V. MARKET-WIDE REGULATING AND SPINNING RESERVE DEMAND CURVE

For each cleared Regulating and Spinning Reserve level less than the Market-Wide Regulating and Spinning Reserve Requirement, the Market-Wide Regulating and Spinning Reserve Demand Curve shall be used to set the Market-Wide Regulating and Spinning Reserve constraint Shadow Price. The Regulating and Spinning Reserve Demand Curve is established based on the level of Regulating and Spinning Reserve shortages. As the Regulating and Spinning Reserve shortage increases, the corresponding Regulating and Spinning Reserve Demand Curve value increases as well.

For cleared Market- Wide Regulating and Spinning Reserve levels greater than ninety percent (90%) but less than one hundred percent (100%) of the Market-Wide Regulating and Spinning Reserve Requirement, the Market- Wide Regulating and Spinning Reserve will be priced at $65 per MWh. For cleared Market-Wide Regulating and Spinning Reserve levels less than ninety percent (90%) of the Market-Wide Regulating and Spinning Reserve Requirement, the Market- Wide Regulating and Spinning Reserve will be priced at $98 per MWh.

VI. MARKET-WIDE UP RAMP CAPABILITY DEMAND CURVE

When the cleared Up Ramp Capability level is less than the Market-Wide Up Ramp Capability Requirement, the Up Ramp Capability price is determined using a Market-Wide Up Ramp Capability Demand Curve. The price is related to the amount of Up Ramp Capability cleared relative to the Market-Wide Up Ramp Capability Requirement, determined as follows:

i. If less than 9% of the requirement level has cleared, the price is $31/MWh.

ii. If less than 13% of the requirement level has cleared, but more than or equal to 9% of the requirement level has cleared, the price is $29/MWh.

iii. If less than 18% of the requirement level has cleared, but more than or equal to 13% of the requirement level has cleared, the price is $27/MWh.

iv. If less than 21% of the requirement level has cleared, but more than or equal to 18% of the requirement level has cleared, the price is $25/MWh.

v. If less than 26% of the requirement level has cleared, but more than or equal to 21% of the requirement level has cleared, the price is $23/MWh.

vi. If less than 37% of the requirement level has cleared, but more than or equal to 26% of the requirement level has cleared, the price is $18/MWh.

vii. If less than 47% of the requirement level has cleared, but more than or equal to 37% of the requirement level has cleared, the price is $14/MWh.

viii. If less than 53% of the requirement level has cleared, but more than or equal to 47% of the requirement level has cleared, the price is $12/MWh.

ix. If less than 100% of the requirement level has cleared, but more than or equal to 53% of the requirement level has cleared, the price is $5/MWh.

x. If more than or equal to 100% of the requirement level has cleared, the price is $0/MWh.

xi. The Market-Wide Up Ramp Capability Demand Curve price will be determined by the Transmission Provider to balance tradeoffs between increased costs of the additional system flexibility and the operational savings. Because Up Ramp Capability provides capacity that can be converted to Energy in a future Dispatch Interval in response to uncertain events, the Transmission Provider approach for determining the Market-Wide Up Ramp Capability Demand Curve price shall include the variability of the market-wide forecasted changes in load and Scheduled Interchange while considering the contribution of non-dispatchable generation served by the dispatchable system resources. It is not required that the Market-Wide Up Ramp Capability Demand Curve price attempts to ensure that Up Ramp Capability levels will cover all potential events.

VII. MARKET-WIDE DOWN RAMP CAPABILITY DEMAND CURVE

When the cleared Down Ramp Capability level is less than the Market-Wide Down Ramp Capability Requirement, the Down Ramp Capability price is determined using a Market-Wide Down Ramp Capability Demand Curve. The price is related to the amount of Down Ramp Capability cleared relative to the Market-Wide Down Ramp Capability Requirement, determined as follows:

i. A single demand curve price is used for all levels of cleared Down Ramp

Capability.

The Market-Wide Down Ramp Capability Demand Curve price will be determined by the Transmission Provider to balance tradeoffs between increased costs of the additional system flexibility and the operational savings. Because Down Ramp Capability provides capacity that can be converted to Energy in a future Dispatch Interval in response to uncertain events, the Transmission Provider approach for determining the Market-Wide Down Ramp Capability Demand Curve price shall include the variability of the market-wide forecasted changes in load and Scheduled Interchange while considering the contribution of non-dispatchable generation served by the dispatchable system resources. It is not required that the Market-Wide Down Ramp Capability Demand Curve price attempts to ensure that Down Ramp Capability levels will cover all potential events. The Market-Wide Down Ramp Capability Demand Curve price will be set to $0/MWh, to disable the product after the removal of Dispatchable Intermittent Resource eligibility.

VIII. MARKET-WIDE SHORT-TERM RESERVE DEMAND CURVE

When the cleared Short-Term Reserve level is less than the Market-Wide Short-Term Reserve Requirement, the Market-Wide Short-Term Reserve Demand Curve shall be used to set the Market-Wide Short-Term Reserve constraint Shadow Price. The price is determined as follows:

i. If less than 2500 MW of the requirement level has cleared, the price is $500/MWh.

ii. If less than 2600 MW of the requirement level has cleared, but more than or equal to 2500 MW of the requirement level has cleared, the price is $478/MWh.

iii. If less than 2800 MW of the requirement level has cleared, but more than or equal to 2600 MW of the requirement level has cleared, the price is $434/MWh.

iv. If less than 2900 MW of the requirement level has cleared, but more than or equal to 2800 MW of the requirement level has cleared, the price is $394/MWh.

v. If less than 3000 MW of the requirement level has cleared, but more than or equal to 2900 MW of the requirement level has cleared, the price is $393/MWh.

vi. If less than the Market-Wide Short-Term Reserve Requirement has cleared, but more than or equal to 3000 MW of the requirement level has cleared, the price is $100/MWh.

vii. If more than or equal to the Market-Wide Short-Term Reserve Requirement has cleared, the price is $0/MWh. The Market-Wide Short-Term Reserve Requirement shall be no less than 3000 MW.

viii. The Market-Wide Short-Term Reserve Demand Curve price will be determined by the Transmission Provider to balance tradeoffs between increased costs of the additional system flexibility and the operational savings. The determination of the Market-Wide Short-Term Reserve Demand Curve price is not required to ensure that Short-Term Reserve levels will cover all potential events.

SCHEDULE 30

EMERGENCY DEMAND RESPONSE INITIATIVE

I. GENERAL

Schedule 30 provides for the commitment and dispatch of interruptible demand, behind-the-meter generation and other demand resources that are capable of helping meet the energy balance during NERC Energy Emergency Alert 2 (“EEA2”), Alert 3 (“EEA3”), or any other types of Emergency events. Schedule 30 provides procedures for the Transmission Provider to be able to dispatch such resources (“Emergency Demand Response” or “EDR”) during Emergency events. References, within Schedule 30, to Emergency events include both Transmission System and capacity Emergencies. Such procedures provide for reductions in Load and/or increased behind-the-meter generation (*i.e.*, “demand reduction”) to be compensated under the conditions specified below (*i.e.*, “EDR Initiative”). These EDR procedures: (i) enhance the Transmission Provider’s ability to utilize demand response during Emergency events; (ii) enable the Transmission Provider to establish curtailment priorities; (iii) reflect varying costs of EDR options; and (iv) allow the Transmission Provider to evaluate and dispatch EDR Offers in merit order by location and by priority status.

II. EMERGENCY DEMAND RESPONSE PARTICIPATION

A Market Participant within the Transmission Provider Region may become an EDR Participant by complying with these Schedule 30 requirements if it: (i) has the ability to cause a reduction in demand in response to receiving an EDR Dispatch Instruction from the Transmission Provider either because the Market Participant is the operator of a facility capable of reducing demand, or the Market Participant is a Load Serving Entity (“LSE”) or ARC with a contract that entitles the Market Participant to reduce Load at such facility; or (ii) has the ability to cause an increase in output from a behind-the-meter-generation resource to enable a net demand reduction, in response to receiving an EDR Dispatch Instruction from the Transmission Provider. Only a Market Participant is allowed to register to become an EDR Participant on behalf of an asset owner and be an eligible EDR Participant by submitting EDR Offers to the Transmission Provider to reduce demand during an Emergency event.

EDR Participants must be able to receive an EDR Dispatch Instruction from the Transmission Provider via XML. EDR Participants must utilize metering equipment that meets the requirements, including, but not limited to, the ability to provide integrated hourly kWh values on a Commercial Price Node ("CPNode") basis. EDR Participants may provide hourly kWh values for non-interval Metered demand reductions (*e.g.*, direct Load control) using the alternative Measurements and Verification procedures provided in Attachment TT. Measurement of demand reductions shall be made on an EDR resource basis, aggregated across assets that define the EDR resource, to enable the EDR Participant's demand reduction to be identified with an LMP; EDR Offers can set the Real-Time Ex Post LMP.

If the behind-the-meter-generation resource designated by an EDR Participant historically is operated during non-Emergency conditions, the Energy that can be offered under the EDR Initiative is the increase in output from a behind-the-meter-generation resource to enable a net Demand reduction, in response to receiving an EDR Dispatch Instruction from the Transmission Provider. Determination of such output shall be based on the EDR Offer and the amount of load reduction provided, consistent with Section VII below or Attachment TT. If a Demand reduction is subject to a contractual agreement with an LSE, then the operator of the facility will be entitled to submit an EDR Offer for the specified Demand reduction to the Transmission Provider only if, and to the extent that, an EDR Offer is consistent with the terms and conditions of the contract with such LSE and the operator of the facility is a Market Participant.

EDR Participants shall be required to identify in their EDR Offers if the Demand reduction can be variable or alternatively provide a specific level of Demand reduction. Upon receipt of an EDR Dispatch Instruction, an EDR Participant shall either: 1) curtail to the firm service level specified in their EDR Offer; or 2) provide a specific level of Demand reduction as specified in their EDR Offer. EDR Participants electing the first option shall be required to identify an expected peak Load in their EDR Offer, updated daily as required to reflect the amount of Demand reduction achievable.

EDR Participants are responsible for maintaining Demand reduction information, including the amount in MWh of reduced Demand during all types of Emergency events whenever the EDR Participant receives an EDR Dispatch Instruction from the Transmission Provider.

III. EMERGENCY DEMAND RESPONSE REGISTRATION

Prior to participating in the EDR Initiative, a Market Participant must complete the EDR registration form as specified in the BPM for Market Registration and submit it to the Transmission Provider. An EDR Participant and its associated Load asset or behind-the-meter generation asset must be defined in the EDR registration form. EDR Participants that are ARCs must meet all the ARC-specific requirements in Section 38.6.

At the time of EDR registration, an EDR Participant shall provide complete details regarding any limitations on the EDR Participant's ability to reduce Demand, including, but not limited to: (i) information regarding the total number of times that the EDR Participant is able to reduce Demand during the year; (ii) the number of times that the EDR Participant has already reduced Demand during the current year; and (iii) any and all restrictions (including, but not limited to, contractual restrictions) that may preclude the EDR Participant from reducing Demand in the future. These limitations provided at the time of registration but not included in the EDR Offer will have no impact on the Transmission Provider's decision to commit the EDR. It is the responsibility of the EDR Participant to ensure the limitations that exist outside of the parameters outlined in the EDR Offer are not violated.

An EDR Participant that intends to use a behind-the-meter generation resource for the purpose of reducing demand during an Emergency event shall confirm to the Transmission Provider in writing that: (1) it holds all necessary permits (including, but not limited to, environmental permits) applicable to the operation of the behind-the-meter generation resource; (2) it possesses rights to operate the behind-the-meter generation resource that are equivalent to ownership of such unit; and (3) the behind-the-meter generation resource is not a designated Network Resource. Unless notified otherwise, the Transmission Provider shall deem such representation applies each time the behind-the-meter generation resource is used to reduce demand during an Emergency event and that the behind-the-meter generation resource is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits. The EDR Participant shall be solely liable for identification of and compliance with all such applicable permits.

The Transmission Provider shall notify the Market Participant when it has met all required qualifications to become an eligible EDR Participant and that the Market Participant is eligible to submit EDR Offers.

IV EDR OFFER

An EDR Participant seeking to reduce Demand during an Emergency event and receive compensation under this Schedule 30 must submit an EDR Offer to reduce Load to the Transmission Provider no later than 1030 EPT on the day prior to the next Operating Day and will be in effect for the next Operating Day. If an EDR Participant is unable to reduce Demand in accordance with an EDR Offer due to exigent circumstances, then the EDR Participant shall promptly notify the Transmission Provider in accordance with the procedures in the Business Practices Manuals. Such notification must be made prior to the issuance of EDR Dispatch Instructions.

The EDR Offer shall specify: (i) the minimum and maximum amount of the offered Demand reduction (in minimum increments of 0.1 MWh) or; specify the firm service level to which the EDR Participant will curtail Demand and specify the EDR Participant's expected peak Load; (ii) the applicable minimum and maximum number of contiguous Hours for which the Demand reduction must be committed for such curtailments; (iii) shutdown costs associated with a demand reduction, including direct labor and equipment costs and/or opportunity costs; (iv) the number of Hours of advance notice from the Transmission Provider that the EDR Participant requires to reduce Demand; (v) the daily availability of the Demand reduction; (vi) an hourly curtailment offer for such Demand reduction specified in dollars per MWh, not to exceed $3,500/MWh. The hourly curtailment offer is a single dollar per MWh value that is applicable to every Hour of the day. Any EDR Offer shall remain valid until it is modified or revoked by the EDR Participant. EDR Offers must be made for a minimum period of one (1) Operating Day and may not be modified after 1030 EPT on the day prior to the next Operating Day. EDR Offers must be consistent with any applicable contractual agreements with an LSE.

V. ISSUANCE OF EMERGENCY DEMAND RESPONSE DISPATCH INSTRUCTIONS

The Transmission Provider may issue EDR Dispatch Instructions to EDR Participants, based upon factors, including, but not limited to, consideration of: (i) terms and conditions of the EDR Offer; (ii) anticipated need for Demand reduction during Emergency events; (iii) availability of other EDR Demand reductions; (iv) the location of the Demand reduction; and (v) anticipated future Emergency conditions. EDR Dispatch Instructions shall detail: (i) the commencement of such Demand reductions; (ii) the amount of Demand reduction that the EDR Participant shall reduce, including a schedule for modified Demand reductions, if appropriate; and (iii) the duration for such Demand reductions. The Transmission Provider may also issue updates to EDR Dispatch Instructions if changing system conditions warrant such action. Any updates to EDR Dispatch Instructions will be consistent with the EDR Offer. The Transmission Provider's Emergency operating procedures documentation shall provide further detailed information on EDR Dispatch Instructions during Emergency events.

EDR Participants shall be entitled to receive compensation for reducing Demand only to the extent that the EDR Participants comply with the Transmission Provider's EDR Dispatch Instructions. EDR Participants shall not be entitled to compensation for Demand reductions in excess of the EDR Dispatch Instruction amounts (*i.e.*, if Demand was reduced by more than that requested by the Transmission Provider in an EDR Dispatch Instruction), provided that EDR Participants shall be entitled to proportionate compensation if they reduced Demand by a proper fraction of the EDR Dispatch Instruction. If an EDR Participant reduces Demand by more than the EDR Dispatch Instruction during an Emergency event, the EDR Participant will not be allocated Real-Time Revenue Sufficiency Guarantee Charges for deviations in Load, pursuant to Section 40.3.3.2. To the extent that an EDR Demand reduction would have occurred during the EDR Dispatch Instruction time period absent the Transmission Provider issuing an EDR Dispatch Instruction to the EDR Participant, then the EDR Participant will not be entitled to compensation for such Demand reduction.

VI. MEASUREMENT AND VERIFICATION PROCEDURES

Unless an alternate approach is agreed upon by the Transmission Provider and an EDR Participant and such alternate approach is documented in Attachment TT of the Tariff, measurement and verification for EDR Participants with hourly interval Metered data will be based upon actual hourly use in the Hour immediately preceding notification to the EDR Participant of the EDR Dispatch Instruction by the Transmission Provider. If Emergency events occur during sequential days, the relevant data will be based upon the actual hourly usage prior to the first of the sequential Emergency event days.

Except as may otherwise be agreed to, EDR Participants must provide the Transmission Provider with meter information for the Hour prior to notification of the EDR Dispatch Instruction, as well as every Hour during the Demand reduction, except under the following circumstances. When on-site generation is deployed exclusively to support the Demand reduction, the EDR Participant may provide qualified meter data from the on-site generation for each Hour of the Emergency event day. Provision of hourly meter data from the on-site generation will be deemed a certification by the EDR Participant that the on-site generation was not used for any purpose other than to support the Demand reduction during the Emergency event day.

An EDR Participant that achieves Demand reduction through the use of direct load control procedures must provide the Transmission Provider with proposed Measurement and Verification procedures. These procedures must be consistent with Attachment TT in the Tariff and include: (1) a description of the direct Load control system, including communication technology, type of Load(s) which are controlled, proposed control scheme (e.g. cycling or complete Load shed), number of participants, geographic location of participants and other relevant information; (2) a description of Load research data that is used in the analysis; (3) a description of the formulae used to produce the estimate, including all assumptions; and (4) a description of all source information for variables used in the analysis, such as a schedule of Demand reductions according to the time of day and weather conditions (e.g., temperature and humidity index). The Transmission Provider may request additional information from such EDR Participant and/or request appropriate revisions to the proposed Measurement and Verification procedures.

EDR Participants must provide the meter data and/or the results of the direct Load control Measurement and Verification procedures, as specified in the Business Practices Manuals, to the Transmission Provider within fifty-three (53) Calendar Days after the Demand reduction, in order to be eligible to receive compensation.

VII. COMPENSATION

EDR Participants that reduce Demand in response to an EDR Dispatch Instruction from the Transmission Provider shall receive the higher of the applicable Hourly Real-Time Ex Post LMP revenue for the associated CPNode of the EDR Participant or the EDR cost recovery during the period of actual Demand reductions. EDR cost recovery is the sum of (i) the shutdown cost and (ii) the lesser of (a) the amount of hourly verifiable Demand reduction or (b) the hourly Dispatch Instruction for each Hour multiplied by the hourly curtailment offer during the period of actual Demand reductions.

EDR Participants must submit documentation of Demand reductions made in response to EDR Dispatch Instructions to enable the EDR Participant to verify in writing under oath to the Transmission Provider that the Demand reductions actually occurred during an Emergency event. EDR Participants must verify in writing to the Transmission Provider that the amount of Demand reductions were made in direct response to the Transmission Provider's EDR Dispatch Instruction and that the Demand reductions otherwise would not have been made.

EDR Participants that receive EDR Dispatch Instructions in response to submitted EDR offers but do not reduce Demand in response to an EDR Dispatch Instruction from the Transmission Provider to the levels specified in the EDR Dispatch Instruction, and adjusted for the Demand Reduction Tolerance, shall not be guaranteed cost recovery for such failure to make Demand reductions. The Demand Reduction Tolerance is equal to (i) the EDR Dispatch Instruction MWhs multiplied by ninety-five percent (95%). EDR Participants that reduce Demand in response to an EDR Dispatch Instruction between the levels specified in the EDR Dispatch Instruction and the Demand Reduction Tolerance will be guaranteed cost recovery for provision of Demand reductions. In addition, such EDR Participants failing to reduce Demand shall be charged an amount equal to the Demand Reduction Shortfall multiplied by the Hourly Real-Time Ex Post LMP of the associated Load CPNode. The Demand Reduction Shortfall is calculated as: (i) the Demand Reduction Tolerance minus the actual Demand reduction; or (ii) zero (0), whichever is greater.

Any reductions in Demand by an EDR Participant shall be subject to verification and potential investigation by the Transmission Provider and the Federal Energy Regulatory Commission to confirm the validity of all EDR Participant assertions.

VIII. PAYMENTS

The sum of the EDR Initiative payments made in an Hour in excess of market revenues shall be funded through an assessment of debits on Market Participants on a *pro rata* basis, based on the Metered Load Ratio Share in the local Balancing Authority Area(s) where the Emergency event occurred that served Load during the EDR Dispatch Instruction period in that same Hour. Any credits that result from EDR Participant(s) failure to reduce Demand as described in Section V shall be allocated in the same *pro rata* basis as costs are allocated in Section VI.

Tab C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)** **)**	**Docket No. ER25-___-000**

PREPARED DIRECT TESTIMONY OF
TODD RAMEY
SENIOR VICE PRESIDENT MARKETS AND DIGITAL STRATEGY

PREPARED DIRECT TESTIMONY OF
TODD RAMEY
FILED ON BEHALF OF THE
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND RELATIONSHIP TO THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

A. My name is Todd Ramey. I am employed by Midcontinent Independent System Operator, Inc. ("MISO") as its Senior Vice President, Markets and Digital Strategy. MISO is located at 720 City Center Drive, Carmel, Indiana, 46032.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I attended Purdue University where I received an undergraduate degree in engineering. I also hold a graduate degree in Business Administration from Butler University. I have worked in the electric industry for thirty-six years. For the first thirteen years of my career, I worked in generation and transmission system operations for an integrated utility in the Midwest. Since 2001, I have held various management positions with MISO in areas related to wholesale market design, development, and operations. I currently hold the position of Senior Vice President, Markets and Digital Strategy.

Q. PLEASE EXPLAIN YOUR CURRENT ROLE AND JOB RESPONSIBILITIES.

A. In my current role as Senior Vice President, Markets and Digital Strategy, I lead MISO's markets and technology transformation efforts. I manage teams focused on emerging technologies, transforming and maturing capabilities, and developing and executing market design and evaluating enhancements. This work drives system and market reliability, and helps to meet the needs of MISO's customers in the future.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support MISO's proposed improvements to shortage pricing by updating the Value of Lost Load ("VOLL"), updating the Operating Reserve Demand Curve ("ORDC"), and decoupling the Emergency Demand Response ("EDR") offer cap from the updated VOLL.

II. PRICE FORMATION AND SHORTAGE PRICING OVERVIEW

Q. PLEASE DESCRIBE MISO'S MARKET DESIGN GUIDING PRINCIPLES.

A. MISO, in concert with stakeholders, articulated the market design guiding principles below in 2014. Even before they were expressly listed, these principles guided MISO's establishment of its markets and MISO has used the principles since 2014 to holistically guide its market design enhancements. MISO's market design guiding principles are to:

- Support an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity;
- Facilitate non-discriminatory market participation regardless of resource type, business model, sector or location;
- Develop transparent market prices reflective of marginal system cost and cost allocation reflective of cost-causation and service beneficiaries;
- Support market participants in making efficient operational and investment decisions; and,
- Maximize alignment of market requirements with system reliability requirements.

Q. HOW DO THESE PRINCIPLES GUIDE PRICE FORMATION RULES IN MISO'S MARKETS?

A. MISO's markets pursue economic efficiency by using least-cost and co-optimization approaches and software in both the Day-Ahead Market and the Real-Time Market. In particular, MISO uses Security Constrained Unit Commitment ("SCUC") and Security Constrained Economic Dispatch ("SCED"), and co-optimizes Energy and Ancillary Services.

MISO's market rules are essentially technology-neutral, while also considering and addressing any unique characteristics of particular Resource types (such as demand response and storage) to give them viable market participation models.

Based on offered values and modeled system conditions, market prices aim to reflect system conditions – ranging from normal, tight or shortage conditions – and the marginal cost of serving load reliably.

By reflecting system conditions, market prices send the proper price signals to incent appropriate operational and market behavior. For example, under shortage conditions, higher prices will incent increased supply and decreased demand. From a long-term perspective, price signals can also incent or guide investment, as well as entrance or exit decisions.

Market and reliability requirements are aligned through market rules that enable prices to reflect the marginal cost of maintaining reliability.

Q. WHAT IS SHORTAGE OR SCARCITY PRICING?

A. Shortage or scarcity pricing refers to the notion of increasing Day-Ahead and Real-Time energy prices above the incremental cost of the marginal resource under conditions when the system is short on generation capacity, which manifests itself as the inability of MISO to procure sufficient reserves. The words "shortage" and "scarcity" are generally used interchangeably, but for this filing, MISO will focus on referring to shortage pricing. In the MISO Region, reserve shortage pricing utilizes "demand curves" to provide a price for the reserve shortage(s) to signal the tight conditions to Market Participants. MISO market signals are the most effective and efficient mechanism to incentivize resource behaviors that promote reliability on the Bulk Electric System.

Q. WHAT IS THE BACKGROUND OF SHORTAGE PRICING IN THE MISO REGION?

A. MISO's participation in the technical conferences and workshops as part of the Commission's price formation efforts in Docket No. AD14-14-000 has guided MISO's development of the shortage pricing mechanisms in the MISO Region. In particular, MISO has developed shortage pricing mechanisms consistent with the Commission's stated price formation goals articulated in Docket No. AD14-14-000. Those goals are:

- Maximize market surplus for consumers and suppliers;
- Provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability;
- Provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and,
- Ensure that all suppliers have an opportunity to recover their costs.

Q. PLEASE SUMMARIZE MISO'S PREVIOUS EFFORTS TO IMPROVE SHORTAGE PRICING.

A. MISO's development of this filing's shortage pricing proposal is partly a response to the IMM's recommendations (2016-1) to update the VOLL and the ORDC. In response to the IMM's recommendations, MISO included shortage pricing improvements in MISO's market design plans and in MISO's Reliability Imperative Framework.

Since 2019, MISO has been working on shortage pricing reform efforts and has been tracking these efforts in the MISO Dashboard[1], in the item "Continued Reforms to Improve Scarcity Pricing and Price Formation (fka IR071) MSC-2019-1." The shortage pricing improvements were framed in 2019 as an issue statement to be addressed in consultation with the Market Subcommittee ("MSC"), and stakeholder discussions commenced in 2020. An Emergency Pricing Evaluation Paper was released in September 2020[2], which focused on near-term enhancements to improve price formation during emergency conditions in the MISO footprint. Then in May 2021, MISO followed up with a Scarcity Pricing Evaluation Paper[3] which focused specifically on near-term enhancements to improve price formation during shortage conditions in the MISO footprint.

MISO designed and implemented several improvements to shortage pricing in 2021 and 2022. MISO implemented Short-Term Reserves ("STR") in December 2021 and made

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1 *See* MISO Dashboard, Continued Reforms to Improve Scarcity Pricing and Price Formation (fka IR071) MSC-2019-1, *available at*: https://www.misoenergy.org/engage/MISO-Dashboard/continued-reforms-to-improve-scarcity-pricing-and-price-formation/.

2 *See* Emergency Pricing Evaluation, MISO (September 2020), *available at*: https://cdn.misoenergy.org/RAN%20Emergency%20Pricing%20Evaluation%20Paper%20Sept%202020475337.pdf.

3 *See* Scarcity Pricing Evaluation, MISO (May 2021), *available at*: https://cdn.misoenergy.org/20210513%20MSC%20Item%20XX%20Scarcity%20Pricing%20Evaluation%20Paper550162.pdf.

additional STR demand curve improvements in November 2022. Fast Start Resource eligibility in ELMP, during capacity emergency conditions, was expanded to four hours in September 2021. Emergency Pricing Offer Floor improvements were made in September 2021 and Offline pricing enhancements were made in October 2021. The notification requirement for Reserve Zone reconfiguration for emergency conditions was removed in October 2021. In December 2021, the $200 step was removed from the ORDC, to reduce the likelihood of OR shortage due to economic considerations. Improvements were also made to the Ramp Capability Product demand curve in November 2022, which replaced the single $5/MWh step with a curve that increased up to $31/MWh.

In 2023, MISO kicked off discussions on the next phase of the Scarcity Pricing reform efforts at the January MSC meeting. Using lessons learned from the financial impact of Hurricane Laura, MISO first focused on alternatives for pricing and cost allocation during extreme emergency conditions. After numerous MSC presentations, including multiple rounds of stakeholder feedback, MISO filed Forced-Off Asset ("FOA")[4] enhancements with FERC in February 2024. These changes were approved by FERC[5] and went live on June 3, 2024.

III. MISO'S RELIABILITY IMPERATIVE

Q. WHAT IS THE RELIABILITY IMPERATIVE?

A. MISO introduced the Reliability Imperative framework in 2020 to address the urgent and complex challenges to electric system reliability in the MISO Region. At that time, MISO

[4] FOA enhancements define settlement adjustments needed when certain Emergency events result in extreme operational and financial impacts pertaining to assets disconnected by significant forced transmission outages.

[5] FERC accepted the FOA Tariff revisions on May 31, 2024 (Docket Nos. ER24-1191-000 and ER24-1191-001).

published the "MISO's Response to the Reliability Imperative[6]" report as a living document, and MISO released the fourth update in February 2024. The Reliability Imperative is organized into four pillars that continually evolve to adapt with the pace of change and magnitude and complexity of that change. In fact, two of the pillars were expanded and renamed in 2022 to recognize the significant progress made and the additional requirements needed within the framework. Below is a brief discussion of each pillar, which consist of numerous interconnected and sequenced initiatives:

1. The Market Redefinition pillar enhances and optimizes MISO's market constructs and products to ensure they continue to deliver reliability and value in the face of fleet change, extreme weather events, electrification, and load additions.
2. The Operations of the Future pillar focuses on the skills, processes and technologies needed to ensure MISO can effectively manage the grid of the future under increased complexity.
3. The Transmission Evolution pillar (previously Long-Range Transmission Planning) holistically assesses the region's future transmission needs based on the ongoing shift in the resource fleet and the substantial projected increase in load while considering the allocation of transmission costs.
4. The System Enhancements pillar (previously Market System Enhancement) supports and enables the transformational efforts across the Reliability Imperative by focusing on future-proofing the technological infrastructure by

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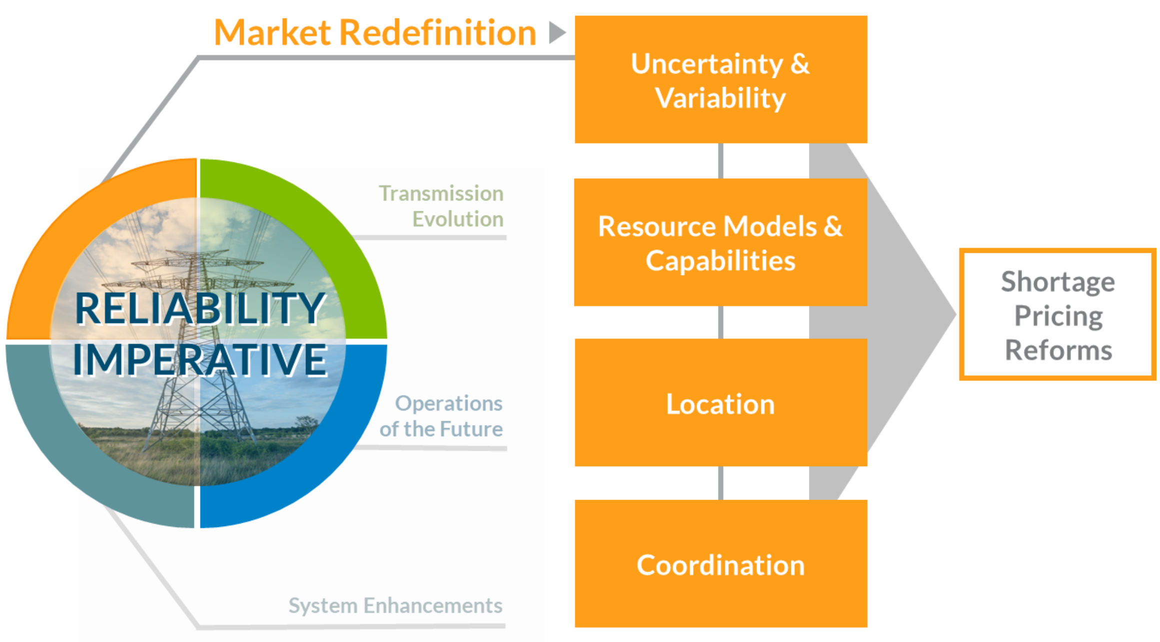
6 *See* MISO's Response to the Reliability Imperative, *available at*: https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/.

adopting a hybrid cloud capability, fortifying cybersecurity, and integrating advanced data analytics. Within this pillar, the Market System Enhancement ("MSE") program ensures that MISO can upgrade, build, and launch new systems with improved performance, security, and architectural modularity.

Q. HOW DO THE PROPOSED SHORTAGE PRICING IMPROVEMENTS FIT WITHIN THE RELIABILITY IMPERATIVE?

A. Updating the VOLL and the ORDC, and decoupling the EDR offer cap from the updated VOLL, are part of the Market Redefinition pillar. Market Redefinition focuses on improvements needed to reliably and efficiently manage the transmission system while the resource portfolio evolves. Shortage pricing improvements will establish appropriate price signals before and during reserve shortage conditions to increase energy production and reduce consumption. The graphic below highlights the relationship of the scarcity pricing reforms to the market redefinition pillar of the reliability imperative:



IV. THE NEED TO UPDATE VOLL, ORDC, AND EDR PRICE CAP

Q. WHAT IS VALUE OF LOST LOAD ("VOLL")?

A. VOLL (i.e., Value of Lost Load) represents the price that demand is willing to pay to avoid loss of service. Currently, the Tariff defines the VOLL to be $3,500/MWh, which is both a price cap, and an administrative price under severe Capacity shortage conditions.

Q. WHAT ARE THE PRIMARY ISSUES WITH AND OPPORTUNITIES TO IMPROVE MISO'S CURRENT SHORTAGE PRICING MECHANISM?

A. MISO has identified several issues with and opportunities to improve shortage pricing mechanisms. The first is that the VOLL has not been updated since before the launch of the Ancillary Services Market in 2009. When used as a price cap, valid pricing signals can be truncated during reserve shortages and/or transmission constraint violations. When used during capacity emergencies in which MISO is forced to shed firm loads, this value significantly understates the current Willingness To Pay values of MISO electricity consumers. In addition to short-term incentives, appropriate shortage prices encourage market participant hedging behaviors such as greater Day-Ahead Market participation. A second opportunity is to improve the ORDC, which is currently dominated by two steps of $1,100 and $2,100/MWh. This demand curve should increase along with Operating Reserve deficits, to reflect the declining marginal reliability of the system.

Q. HOW DOES VOLL CURRENTLY FUNCTION IN THE MISO MARKETS?

A. The VOLL presently serves four functions in MISO's Day-Ahead and Real-Time Markets. VOLL serves as the: (1) energy and reserve price caps, (2) capacity emergency load shed administrative price cap, (3) reference point for the top of the ORDC, and (4) Emergency Demand Response Offer Cap.

Q. HOW DOES VOLL SERVE AS A REFERENCE POINT FOR THE TOP OF THE ORDC?

A. MISO has five reserve products to help ensure grid reliability: (1) Regulation Reserve; (2) Spinning Reserve, (3) Supplemental Reserve; (4) Ramp Capability; and (5) Short-Term Reserve. The original three products were Regulation, Spinning, and Supplemental Reserves; the Ramp Capability, and Short-Term Reserve products were added in recent years. For each reserve product, MISO specifies a target requirement, which can vary at different times or conditions. When there is insufficient supply to satisfy the reserve requirement, a price is established using a "demand curve." The demand curve should reflect the increased reliability risk for that reserve shortage, while considering the relative (and sometimes cumulative) risks of other reserve shortages.

The ORDC reflects the combined need of Regulating, Spinning, and Supplemental Reserves. These products must be deliverable within 10 minutes (or fewer for Regulating Reserves) to ensure the grid can withstand the loss of the largest supply source. Thus, an extended deficiency of Operating Reserve must be avoided. The ORDC has the highest prices, as it is used to escalate prices towards VOLL (the price cap) as cleared Operating Reserves are depleted. The ORDC is largely defined by two steps, $1,100 and $2,100. In the most extreme Operating Reserve shortages (i.e., when less than 4% of the Operating Reserve requirement is cleared), the ORDC is set to the VOLL minus the Regulating Reserve Demand Curve (which is updated monthly).

Q. HOW DOES VOLL FUNCTION AS THE EDR OFFER CAP?

A. The EDR Offer Cap is defined to be VOLL in Schedule 30 of the Tariff. EDRs can be called upon during NERC Energy Emergency Alert 2 ("EEA2"), Energy Emergency Alert 3 ("EEA3"), or any other type of emergency event.

Q. HAS THE INDEPENDENT MARKET MONITOR ("IMM") MADE ANY RECOMMENDATIONS REGARDING SHORTAGE PRICING IN THE MISO REGION?

A. Yes. In 2016, the IMM recommended that MISO "[i]mprove shortage pricing by adopting an improved contingency reserve demand curve that reflects the expected value of lost load."[7] The IMM noted that "[f]or MISO to implement this recommendation, it would need to update its VOLL assumption and determine the slope of the ORDC based on how capacity levels affect the probability of losing load."[8]

More recently, MISO and the IMM recognized that the ORDC can impact the effectiveness of congestion management. Therefore, in 2022, the IMM recommended that MISO "[e]xpand the TCDCs [Transmission Constraint Demand Curves] to allow MISO's market dispatch to reliably manage network flows."[9] The IMM explained the ORDC's impact on the effectiveness of congestion management, stating "[d]uring capacity emergencies, the value of energy and reserves under the ORDC can prevent the dispatch model from reducing output when needed to manage network flows because the value of managing the

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7 2016 State of the Market Report, Potomac Economics (June 2017), at p. 77, *available at* https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-SOM_Report_Final_6-30-17.pdf (last visited Oct. 23, 2024).

8 *Id.* at p. 78

9 2023 State of the Market Report, Potomac Economics (June 2024), at pp. 103-104, *available at* https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf (last visited Oct. 24, 2024).

transmission constraint is not high enough. Likewise, when the RDT or other constraints are violated, the dispatch model may not move generation as needed to manage the flows over other constraints. This has often compelled MISO operators to manually dispatch generation to reduce flows on overloaded constraints, which is costly and distorts market outcomes."[10]

VI. MISO'S ANALYSIS AND STAKEHOLDER ENGAGEMENT

Q. HAS MISO CONDUCTED ANY INTERNAL STUDIES TO DETERMINE THE APPROPRIATE UPDATES FOR VOLL, ORDC, AND EDRS?

A. Yes. MISO evaluated its scarcity pricing structure following the IMM's 2016 recommendation. In the December 2019 Aligning Resource Availability and Need ("RAN") Whitepaper, MISO identified the need to enhance emergency pricing and laid out its plan to address the problem.[11] MISO also published the Emergency Pricing Evaluation Paper in September of 2020 and the Scarcity Pricing Evaluation Paper in May of 2021.[12] The goals of MISO's scarcity or shortage pricing reform are to:

1. Incentivize appropriate market behavior;
2. Improve congestion management throughout scarcity events;
3. Value reserve shortages appropriately;

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10 *Id.*, at pp. 103-104.

11 Aligning Resource Availability and Need, MISO (December 2019), available at https://cdn.misoenergy.org/Aligning%20Resource%20Availability%20and%20Need%20(RAN)410587.pdf

12 Emergency Pricing Evaluation, MISO (September 2020), available at https://cdn.misoenergy.org/RAN%20Emergency%20Pricing%20Evaluation%20Paper%20Sept%202020475337.pdf;

Scarcity Pricing Evaluation, MISO (May 2021) available at https://cdn.misoenergy.org/20210513%20MSC%20Item%20XX%20Scarcity%20Pricing%20Evaluation%20Paper550162.pdf

4. Provide market transparency; and
5. Minimize manual market intervention.

Q. DID MISO ENGAGE STAKEHOLDERS ON THE APPROPRIATE UPDATES TO VOLL, ORDC, AND EDRS?

A. Yes. MISO has discussed the appropriate shortage pricing reforms with Stakeholders in its Market Subcommittee. In January 2021, MISO gave two presentations at the MSC tilted "MISO Resource Availability and Need-Scarcity Pricing Enhancement Overview" and "Discuss implications of August 27 Maximum Generation Events." Following the January 2021 Meeting, MISO engaged with stakeholders on the proposed changes during seven MSC meetings and through five stakeholder feedback requests in 2023 and 2024.[13] Through the MISO Market MSC meetings, MISO educated stakeholders regarding shortage pricing objectives, and developed recommendations to update the VOLL, ORDC, and EDR Offer Cap. MISO also published a Scarcity Pricing White Paper for stakeholders to review and provide feedback.[14] MISO provided the MSC with draft Tariff revisions and sought their feedback. Stakeholder input was incorporated into several design choices, including the creation of a new market price circuit breaker, aspects of the ORDC design such as an appropriate value for the curve floor, retention of administrative VOLL pricing during MISO-directed capacity load-shedding (a.k.a. NERC EEA3 Emergencies),

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[13] MISO engaged with stakeholders during the August 23, 2023, January 18, 2024, February 29, 2024, April 18, 2024, May 23, 2024, July 9, 2024, and August 22, 2024 MSC meetings. Stakeholder feedback requests were made at the January 18, 2024, February 29, 2024, April 18, 2024, July 9, 2024, and August 22, 2024 MSC meetings. A full listing of the MSC meetings and their respective agendas is publicly available on the MISO web site. *See* Market Subcommittee (MSC), MISO, https://www.misoenergy.org/engage/committees/market-subcommittee/ (last visited Oct. 25, 2024).

[14] *See* Scarcity Pricing White Paper: Value of Lost Load and Operating Reserve Demand Curve, MISO (March 2024), available at: https://cdn.misoenergy.org/20240418%20MSC%20Item%2004d%20Scarcity%20Pricing%20White%20Paper%20VOLL%20and%20ORDC632355.pdf

weighting factors of VOLL components, and maintaining the EDR Offer Cap of $3,500/MWh.

MISO believes this systematic approach, involving stakeholders at each stage of the process, has resulted in a set of market enhancements that will significantly improve the economic incentives to reduce the number and severity of energy and reserve shortages.

VII. PROPOSED UPDATES TO VOLL, ORDC, AND EDR

Q. HOW IS MISO PROPOSING TO UPDATE THE VOLL?

A. MISO is proposing to increase the VOLL to $10,000/MWh, in its function as a price cap for Locational Marginal Prices and Market Clearing Prices, and as the administrative price applied during capacity load-shed events. In connection with these functions, MISO proposes to define the VOLL as the Pricing VOLL.

Q. WHY IS MISO PROPOSING TO UPDATE THE ORDC?

A. The current ORDC does not fully reflect the reliability conditions of the grid. It is largely defined by two steps ($1,100 and $2,100) and does not increase as the Operating Reserve deficiency worsens, not considering the most extreme of deficits. The first $1,100 step can also provide challenges for congestion management, even for small Operating Reserve deficits.

Q. HOW IS MISO MODIFYING THE ORDC?

A. MISO proposes to modify the ORDC by developing a Loss-of-Load-Probability Curve to quantify the risk of losing load for decreasing amounts of Operating Reserves, and by updating and using a different kind of VOLL to scale that curve. In particular, the Loss-of-Load Probability Curve shall be scaled by an ORDC VOLL of $35,000/MWh, which

MISO defines as the System VOLL. The System VOLL reflects the financial impact of dropping load across all customer classes. An ORDC floor of $600 balances "economic scarcity" with the increased burdens on congestion management of Operating Reserve shortages. An $1,100 ORDC step also helps clear more reserves below MISO's Most Severe Single Contingency. An ORDC ceiling of $6,000 allows market prices to appropriately approach the Pricing VOLL during severe Operating Reserve shortages and prevents the overshadowing of other important pricing components (*e.g.*, other reserve product shortages, fuel costs, congestion and losses).

Q. IS MISO PROPOSING ANY SAFEGUARD MECHANISMS FOR LONG-LASTING EMERGENCY EVENTS?

A. Yes. The proposed VOLL and ORDC changes described above are designed to establish appropriate prices during short-term Operating Reserve and/or energy shortages. For extended-duration energy shortage events, safeguards are warranted to mitigate financial risks when there is a reduced need for reliability to be enhanced by higher prices as shortage conditions persist. Stakeholder discussions further amplified the potential financial risk posed on Market Participants by the application of very high shortage prices if a Capacity Emergency lasts for an extended period. In response, MISO explored, and then recommended, the adoption of Pricing VOLL "circuit breakers" for shortage conditions of longer duration.

Q. WHAT ARE THE PROPOSED PRICING VOLL CIRCUIT BREAKER MECHANISMS?

A. MISO proposes to include in the Tariff "circuit breakers" that will reduce the Pricing VOLL when the MISO-declared EEA-Level 3 Capacity Emergency lasts longer than four (4) hours. The application of the proposed circuit breakers is summarized below:

- First, if the EEA-Level 3's cumulative duration reaches four (4) hours, the Pricing VOLL for the Real-Time Market shall be reduced to $5,000/MWh. Such duration shall not be deemed ended, but rather only paused, when MISO declares an end to the EEA-Level 3 but declares that Capacity shortage conditions remain. The cumulative EEA-Level 3's duration is deemed ended when MISO declares an end to Capacity shortage conditions.
- Second, when Capacity shortage conditions under the EEA-Level 3 continue at the time the Day-Ahead Market closes, the Pricing VOLL shall be reduced to $5,000/MWh, and shall be applied on the next Operating Day for both the Day-Ahead Market and the Real-Time Market.
- Third, if the Capacity shortage conditions under the EEA-Level 3 continue at the close of any additional Day-Ahead Market(s), the Pricing VOLL shall be reduced to $2,000/MWh for both the Day-Ahead Ahead Market and the Real-Time Market for the next Operating Day(s).
- Fourth, after the end of the shortage conditions described in the three preceding paragraphs, the Pricing VOLL will cease to be applied, and it shall be reset to the initial value of $10,000/MWh as a price cap, and for potential application as an administrative price to future shortage conditions. The Pricing VOLL shall be thus

reset at the end of the current Operating Day, if MISO declares an end to the Capacity shortage conditions before the close of the Day-Ahead Market; or at the end of the next Operating Day, if MISO declares an end to the Capacity shortage conditions after the close of the Day-Ahead Market

Q. WHY IS MISO PROPOSING TO DECOUPLE THE VOLL FROM THE EDR OFFER CAPS?

A. Given the proposed increases to the Pricing VOLL, MISO has concerns that applying a significantly higher cap to potential EDR offers would overstate the relative value of EDRs, compared to other types of supply resources.

Q. HOW IS MISO PROPOSING TO DECOUPLE THE VOLL FROM THE EDR OFFER CAPS?

A. After internal and external dialogues to identify potential solutions, MISO adopted the first of the following options: setting the EDR Offer Cap to some fixed value; utilizing the same Order No. 831 process used to validate additional costs of other resources that submit offers above the hard price cap; or retiring the EDR product. MISO determined that, in the short-term, it would be appropriate to maintain the EDR Offer Cap at its current level of $3,500/MWh, instead of the significantly higher $10,000/MWh value of the updated Pricing VOLL.

Q. WHAT ARE THE EXPECTED ADVANTAGES OF THE PROPOSED SHORTAGE PRICING IMPROVEMENTS?

A. The proposed shortage pricing changes in the day-ahead and real-time markets will incentivize appropriate participant behaviors on multiple timeframes. In the real-time, appropriately high energy and reserve prices incent increases in emergency supply (generation and imports), as well as decreasing levels of consumption. The updated VOLL corresponds to the latest value that MISO loads are willing to pay to avoid service interruptions. If real-time prices do not surpass the willingness-to-pay of most loads, there is little incentive to develop and implement additional demand flexibility and price-responsiveness.

Beyond the real-time responses, higher potential shortage prices encourage hedging activities in the days and weeks leading up to the real-time. For instance, increased Day-Ahead Market participation by loads allows MISO to economically commit additional longer-lead time resources, and to schedule additional imports into the footprint. Loads that have prudently procured their energy in the day-ahead and/or have enough ability to reduce real-time consumption during periods of high prices, are not impacted by real-time shortage pricing. Rather, the Market Participants that are at most risk are those that did not obtain sufficient energy before the real-time, and are also unresponsive to market pricing signals.

One should also consider the longer-term impacts (beyond the day-ahead and real-time markets) of higher potential shortage prices. While these effects are secondary/tertiary in nature, they are directionally consistent with other longer-term market forces, such as the Planning Resource Auction. Market Participants should consider the potential risks related to shortage pricing when making longer-term decisions about fuel purchases, maintenance planning, power plant upgrades, power-purchase agreements, and even the creation and/or retention of flexible supply resources. Proper pricing signals across these multiple timeframes combine to reduce the likelihood and/or severity of real-time energy supply shortages.

VIII. IMPLEMENTATION TIMELINE

Q. WHAT IS MISO'S PROPOSED EFFECTIVE DATE FOR THE SHORTAGE PRICING RULES?

A. MISO is requesting an effective date of September 30, 2025. The proposed Tariff revisions are being filed now to give MISO sufficient advance time to budget for, prepare, and put in place the software, system, and procedural changes needed to implement the proposed shortage pricing rules.

Q. DOES MISO HAVE A REQUESTED DATE FOR COMMISSION ACTION IN ORDER TO MEET ITS PROPOSED EFFECTIVE DATE?

A. Yes, MISO is requesting the issuance of an acceptance order by March 1, 2025. In order to accommodate MISO's requested September 30, 2025 effective date, MISO must work with its software vendor to make changes to its Market Systems, and processes sufficiently in advance of the effective date. For this reason, MISO respectfully requests that the Commission act on its proposal and issue an order accepting all proposed changes by March 1, 2025.

IX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Affidavit of Todd Ramey

COUNTY OF HAMILTON)
)
STATE OF INDIANA)

Todd Ramey, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Todd Ramey, and the statements contained therein are true and correct to the best of his knowledge and belief.

Todd A. Ramey
Todd Ramey

SUBSCRIBED AND SWORN BEFORE ME, this 22nd day of October, 2024.

Rhiannon Rena Shelley
(Notary Public Signature)

RHIANNON RENA SHELLEY
Clinton County
My Commission Expires
September 27, 2025

Commissioned in Clinton county.

Commission Number: 705772

Commission Expires: 9/27/2025

Tab D

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)** **)**	**Docket No. ER25-___-000**

PREPARED DIRECT TESTIMONY OF
ZAKARIA JOUNDI
EXECUTIVE DIRECTOR, MARKET AND GRID STRATEGY

PREPARED DIRECT TESTIMONY OF
ZAKARIA JOUNDI
FILED ON BEHALF OF THE
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND RELATIONSHIP TO THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

A. My name is Zakaria ("Zak") Joundi. I am employed by Midcontinent Independent System Operator, Inc. ("MISO") as its Executive Director, Market & Grid Strategy. MISO is located at 720 City Center Drive, Carmel, Indiana 46032.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Science degree in electrical engineering, with an emphasis in power systems, from Iowa State University, and a Master of Business Administration degree, with an emphasis in finance, from the Indiana University Kelley School of Business. I joined MISO in 2006 and have held multiple positions of increasing responsibilities that span across generation and transmission planning, market administration, seams administration, data and analytics, and resource adequacy ("RA"). I have also supported numerous MISO initiatives and filings with the Federal Energy Regulatory Commission ("Commission" or "FERC"), including Financial Transmission Rights ("FTR"), seams, RA, and matters related to the Energy & Ancillary Service markets.

Q. PLEASE DESCRIBE YOUR CURRENT ROLE AND JOB RESPONSIBILITIES.

A. In my current role as Executive Director, Market & Grid Strategy, I oversee the team responsible for design of the MISO markets and the assessment of its performance. I also oversee and coordinate stakeholder discussions of, and engagement in, MISO's market enhancement efforts.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support MISO's proposed updates to the Value of Lost Load ("VOLL") and Operating Reserve Demand Curve ("ORDC"), as well as the decoupling of the Emergency Demand Response ("EDR") offer cap from the updated VOLL.

Q. PLEASE PROVIDE AN OVERVIEW OF MISO'S SHORTAGE PRICING PROPOSAL.

A. VOLL represents the price that demand is willing to pay to avoid loss of service. Currently, MISO's Tariff defines the VOLL to be $3,500/MWh, which is both a price cap, and an administrative price under severe Capacity shortage conditions. As discussed in more detail below, this VOLL value was established at the launch of MISO's Ancillary Services Market in 2009 and has not been updated since. As such, it is necessary and appropriate to update the VOLL and ORDC, and decouple the EDR offer cap from the updated VOLL. In this filing, MISO proposes to distinguish two kinds of VOLL: (1) a Pricing VOLL of $10,000/MWh to be used as a price cap and an administrative price; and (2) a System VOLL of $35,000/MWh to be used to scale the ORDC. The two VOLL values have different functions. The Pricing VOLL represents the price consumers are willing to pay to avoid an interruption of electrical service, and is mainly based on consumers with the lowest willingness to pay. This Pricing VOLL is appropriate to use as a price cap (at all times) and also for fixed administrative pricing during emergencies when it is necessary to shed load. The proposed enhancements also include a "circuit breaker" mechanism for reducing the Pricing VOLL when shortage conditions last exceptionally long.

The System VOLL represents the composite price that consumers are willing to pay to avoid an interruption of electrical service. The System VOLL is used to develop an updated ORDC to appropriately reflect the increased possibility of MISO-directed load curtailment as an Operating Reserve deficiency worsens. The updated values will ensure that MISO's shortage pricing rules maintain and enhance compliance with the Commission's requirement that shortage prices reflect load's willingness to pay to avoid service interruption under shortage conditions.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is divided into the following sections:

- Background and Overview of Shortage Pricing;
- MISO's Current Reserve Products and VOLL;
- Need for Updating VOLL and ORDC;
- Application of Administrative VOLL Pricing During EEA – Level 3;
- Proposed VOLL;
- Need for a Pricing VOLL Circuit Breaker;

- Non-Application of $2,000 price cap to Day-Ahead Price-Sensitive Demand Bids and Virtual Demand Bids;
- Proposed ORDC Updates;
- Proposed EDR Offer Cap; and
- Implementation and Effective Date.

II. <u>BACKGROUND AND OVERVIEW OF SHORTAGE PRICING</u>

Q. PLEASE DESCRIBE GENERALLY MISO'S ENERGY AND OPERATING RESERVE MARKETS.

A. MISO administers Day-Ahead and Real-Time Markets for Energy and Operating Reserves (*i.e.*, Regulation, Spinning and Supplemental Reserve). These markets use a process called simultaneous co-optimization to minimize total production and Operating Reserve Capacity costs and ensure suppliers of Energy and Operating Reserves can recover both their Offer costs and Opportunity Costs via Locational Marginal Prices ("LMP") for Energy and Market Clearing Prices ("MCP") for Operating Reserves, or through Day-Ahead and Real-Time Revenue Sufficiency Guarantee Credits or other Make-Whole Payments under MISO's Tariff.

Simultaneous co-optimization is applied to both Security Constrained Unit Commitment ("SCUC") and a Security Constrained Economic Dispatch ("SCED") to commit and/or dispatch Resources, which minimizes the total costs of supplying Energy and Operating Reserves. Simultaneous co-optimization results in lower total production costs because Energy and Operating Reserve needs are considered together, at the same time, rather than sequentially. Through this process, MISO determines schedules for Energy and Operating

Reserves at the same time based on an evaluation of all of the trade-offs involved in resource scheduling. Therefore, if scheduling a resource to produce more Energy and to devote less of its capacity to providing Operating Reserves would decrease energy costs by a certain amount, but would increase Operating Reserve costs by more than that amount, MISO does not dispatch that resource to produce additional Energy and instead schedules that resource to provide Operating Reserves. This process allows MISO to reliably operate its Energy and Operating Reserve markets at the lowest production costs

Q. HOW ARE ENERGY AND OPERATING RESERVES PRICED IN MISO'S MARKETS?

A. The Energy LMPs and Operating Reserve MCPs generated via simultaneous co-optimization, respectively, ensure that the suppliers of Energy and Operating Reserves recover both the cost of their Offers plus Opportunity Costs incurred from adjustments to Energy sales to provide Operating Reserves. As a result, Market Participants are indifferent to selling either Energy or Operating Reserve, which promotes increased participation across all market products.

Simultaneous co-optimization generates LMPs for Energy and MCPs for Operating Reserves for each Hour in the Day-Ahead Market and for every Dispatch Interval in the Real-Time Market. These prices are based on Market Participants' Energy Offers and Operating Reserve Offers, including separate Offers submitted for Regulating Reserves, Spinning Reserves, and Supplemental Reserves. Through the algorithm, and based on such Offers, MISO will commit and dispatch the Resources that will provide the least cost solution to serve Energy and Operating Reserve requirements. In the Day-Ahead Market, this least-cost solution is based on the as-Bid Demand submitted by the Market Participants and Operating Reserve requirements. In the Real-Time Market, this least-cost solution is optimized based upon MISO's short-term Load forecast and Operating Reserve requirements.

Q. WHAT IS SCARCITY OR SHORTAGE PRICING IN THE MISO MARKETS?

A. Scarcity or shortage pricing refers to the notion of increasing day-ahead and real-time energy prices above the incremental cost of the marginal resource under conditions when the system is short on generation capacity, which manifests itself as the inability of MISO to procure sufficient reserves. MISO market signals are the most effective and efficient mechanism to incentivize resource, load and interchange behaviors that promote reliability on the Bulk Electric System whenever there is a shortage of reserves or energy.

The terms scarcity and shortage are often used interchangeably, and MISO has tended to historically use the word scarcity. But for purposes of this Tariff filing, MISO will generally refer to shortage pricing. The shortage pricing term more specifically reflects the need for higher prices when available supply is not only scarce, but actually short of reserve or energy requirements in varying degrees.

Q. PLEASE PROVIDE A BRIEF HISTORY OF THE PRICE FORMATION EFFORTS IN THE MISO REGION.

A. Price formation efforts in the MISO Region have been shaped by a combination of the Commission's guidance on the design of MISO's Ancillary Services Market ("ASM"), and the Commission's rulemaking process addressing price formation and shortage pricing.

This rulemaking process began with an Advanced Notice of Proposed Rulemaking ("ANOPR") regarding shortage pricing. The ANOPR described four ways that shortage pricing can appropriately reflect operating reserve shortage under emergency conditions: (i) increase the energy bid caps and price caps only during an emergency; (ii) raise bid caps only for demand bids, while maintaining generation bid caps; (iii) require a demand curve for operating reserves, such that when available generating capacity falls short of combined energy demand and operating reserve requirements, the market price for energy and operating reserves would increase to specified levels that rise with the severity of the shortage; and (iv) set the market-clearing price at the payment made to participants in an emergency demand response program.

As a result of the rulemaking process, the Commission issued Order No. 719, which ultimately established six specific shortage pricing criteria.

Q. WHAT ARE THE SIX SHORTAGE PRICING CRITERIA THE COMMISSION IDENTIFIED IN ORDER NO. 719?

A. The six shortage pricing criteria identified in Order No. 719 are: (1) improve reliability by reducing demand and increasing supply during periods of operating reserve shortages; (2) make it more worthwhile for customers to invest in demand response technologies; (3) encourage existing generation and demand resources to continue to be relied upon during an operating reserve shortage; (4) encourage entry of new generation and demand resources; (5) ensure that the principle of comparability in treatment of and compensation to all resources is not discarded during periods of operating reserve shortage; and (6) ensure market power is mitigated and gaming behavior is deterred during periods of operating reserve shortages including, but not limited to, showing how demand resources discipline bidding behavior to competitive levels.

Q. DID MISO SATISFY THE CRITERIA OF ORDER NO. 719?

A. Yes, the Commission accepted MISO's Order No. 719 compliance proposal, finding that MISO's shortage pricing rules:

(i) Improve reliability during periods of operating reserve shortages because, as operating reserves are depleted, MISO progressively raises energy and operating reserve prices within reserve zones, thereby increasing supply and reducing demand to improve reliability.

(ii) Make it worthwhile for customers to invest in demand response technologies because elevated prices increase customers' costs for consuming energy.

(iii) Encourage existing generation and demand resources to remain in business because high prices during shortage conditions create incentives for demand reductions and supply resource availability when and where needed most.

(iv) Encourage the entry of new generation and demand resources, as new investment is driven by projections of future market prices and the resultant profits or cost savings; and provide developers with certainty regarding elevated future energy prices during times of supply scarcity.

(v) Treat demand response resources comparably to other resources during operating reserve shortages because they are paid the same prices as generation resources.

(vi) Include appropriate market power mitigation provisions during operating reserve shortages, as MISO works closely with the Independent Market Monitor ("IMM") to evaluate whether market participants are attempting to exercise market power or engage in gaming behaviors, and continually attempts to improve its market rules and procedures.

Q. WHAT WAS THE RELATIONSHIP BETWEEN MISO'S INITIAL SHORTAGE PRICING RULES AND THE ENERGY OFFER CAPS ESTABLISHED BY ORDER NO. 831?

A. MISO's original Market-Wide Operating Reserve Demand Curve was determined using the then Energy Offer Price Cap of $1,000/MWh. Subsequently, Order No. 831 established a hard price cap of $2,000/MWh, as well as a soft offer cap of $1,000/MWh. Thus, MISO needed to revise Schedule 28 of the Tariff to be consistent with the offer caps under Order No. 831.

Q. HOW DID MISO MAKE THE SHORTAGE PRICING RULES IN SCHEDULE 28 CONSISTENT WITH ORDER NO. 831?

A. MISO filed, and the Commission accepted, revisions of Schedule 28 of the Tariff that adopted the $2,000/MWh Energy Offer Hard Price Cap for the determination of the Market-Wide Operating Reserve Demand Curve when cleared reserves are less than ninety-six percent (96%) of the requirement, and adopted the $1,000/MWh Energy Offer Soft Price Cap for such determination when cleared reserves are more than 96 percent of the requirement.[1]

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[1] A subsequent Tariff change tied the clearance threshold to the Most Severe Single Contingency, as defined by the Reserve Sharing Group.

Although not specifically required by Order No. 831, MISO also proposed, and the Commission accepted, the adoption of the Energy Offer Hard Price Cap of $2,000 as a cap on Day-Ahead Price-Sensitive Demand Bids and Virtual Demand Bids. As a part of this filing, MISO is proposing to remove these day-ahead demand bid caps, while retaining the resource offer caps mandated in Order No. 831.

Q. HAS FERC ARTICULATED ANY GOALS FOR PRICE FORMATION?

A. Yes, FERC identified the following price formation goals in Docket No. AD14-14:

- Maximize market surplus for consumers and suppliers;
- Provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability;
- Provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and
- Ensure that all suppliers have an opportunity to recover their costs.

Q. IN GENERAL, HOW DOES MISO'S MARKET DESIGN ALIGN WITH FERC'S PRICE FORMATION GOALS?

A. By using Security Constrained Unit Commitment and Security Constrained Economic Dispatch, and by co-optimizing energy and Operating Reserves, MISO seeks to maintain and enhance the balance of supply and demand in a manner that is economically and operationally beneficial to both suppliers and consumers.

Offers are required to include adequate and accurate parameters, and are cleared by market engines as may be warranted by system conditions, in such a way that the resulting prices (supplemented by make-whole payment rules) ensure cost recovery, and incentivize compliance with MISO's commitment and dispatch instructions in the near-term; and also help incentivize investment in new resources and facilities in the long-term.

Q. WHAT MARKET DESIGN GUIDING PRINCIPLES HAS MISO USED IN ITS MARKET ENHANCEMENT EFFORTS?

A. MISO originally developed the following market design guiding principles in 2014 and has leveraged these principles to guide the solutions being considered and inform our conversations in the stakeholder process.[2]

MISO's market enhancement efforts, including the improvement of shortage pricing, have been based on these guiding principles.

1. Support an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity.
2. Facilitate non-discriminatory market participation regardless of resource type, business model, sector or location.
3. Develop transparent market prices reflective of marginal system cost and cost allocation reflective of cost-causation and service beneficiaries.

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[2] *See* Market Vision, MISO https://www.misoenergy.org/markets-and-operations/market-roadmap/#:~:text=Five%20principles%20serve%20as%20guideposts%20for%20progressing%20toward,reflective%20of%20cost-causation%20and%20service%20beneficiaries%20More%20items (last visited Nov. 25, 2024).

4. Support market participants in making efficient operational and investment decisions.
5. Maximize alignment of market requirements with system reliability requirements.

Q. HOW FREQUENTLY HAS EXTREME SHORTAGE PRICING OCCURRED IN MISO?

A. While investigating the past instances of VOLL shortage pricing, MISO identified that the Day-Ahead Market has not had VOLL pricing, and it has been relatively rare in the Real-Time Market:

- Extreme VOLL pricing has not been seen in the Day-Ahead Market. Day-Ahead Market prices do not get as high as VOLL because of price-sensitive demand bids, import offers, virtual trading, and access to essentially the entire available generation fleet in the Day-Ahead Market. Furthermore, the Day-Ahead Market has never cleared an Operating Reserve ("OR") shortage, so the ORDC has not been applied.
- VOLL shortage pricing in the Real-Time Market is extremely rare. There have been nine 5-minute intervals having an OR deficit and a Marginal Energy Component ("MEC") of the LMP = $3,500/MWh. The Real-Time Market has never cleared below 50% of the OR requirement.[3]

MISO closely monitors extreme shortage pricing intervals, to ensure that VOLL pricing appropriately reflects the reliability risk of the system. If spurious pricing outcomes are encountered, MISO is determined to quickly identify and rectify the underlying cause.

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[3] Presented to the April 18th, 2024 Market Subcommittee, available at https://cdn.misoenergy.org/20240418%20MSC%20Item%2008%20Continued%20Reforms%20to%20Improve%20Scarcity%20Pricing%20and%20Price%20Formation%20(MSC-2019-1)632556.pdf.

III. MISO'S CURRENT RESERVE PRODUCTS AND VOLL

Q. PLEASE LIST MISO'S RESERVE PRODUCTS.

A. MISO's reserve products include Regulating Reserves, Contingency Reserves (Spinning and Supplemental), Ramp Capability, and Short-Term Reserves.

Q. PLEASE BRIEFLY DESCRIBE REGULATING RESERVE.

A. Regulating Reserve is unloaded and loaded Resource Capacity used by the MISO Balancing Authority as necessary to manage the Area Control Error ("ACE") in order to comply with Applicable Reliability Standards.

Regulating Reserve is necessary to: (i) continuously balance the total output of all Resources within the MISO Balancing Authority Area with the total demand of all Loads (including losses) within the MISO Balancing Authority Area plus the Net Scheduled Interchange ("NSI"); and (ii) assist in maintaining the deviation between scheduled Eastern Interconnection frequency and actual Eastern Interconnection frequency within acceptable limits based on Applicable Reliability Standards. Regulating Reserve Deployment is accomplished by using Automatic Generation Control ("AGC") equipment to raise or lower the output of on-line Resources as necessary to follow the moment-by-moment changes in demand and frequency.

Regulating Reserve is cleared and priced every Hour in the Day-Ahead Energy and Ancillary Services Market and every Dispatch Interval in the Real-Time Energy and Ancillary Services Market. Regulating Reserve is settled on an hourly basis in both the Day-Ahead and Real-Time Energy and Ancillary Services Markets. Regulating Reserve can only be supplied by Regulation Qualified Resources available to provide Regulation.

Q. PLEASE BRIEFLY DESCRIBE CONTINGENCY RESERVE.

A. Contingency Reserve consists of unloaded Resource Capacity that is set aside to offset an abnormal supply deficiency event, such as the loss of a large generator or a transmission line carrying significant flow. Contingency Reserve consists of Spinning Reserve and Supplemental Reserve. Spinning Reserve in the Day-Ahead Market is an hourly product, and in the Real-Time Market it is a five-minute product. In both markets, Spinning Reserve is defined as a specified percentage of the total MISO Contingency Reserve requirement that must be immediately available to respond to an abnormal supply deficiency event. MISO establishes this percentage in accordance with the requirements established by the Electric Reliability Organization. Spinning Reserve can be supplied in the Day-Ahead and Real-Time Markets by any Spin Qualified Resource.

Supplemental Reserve in the Day-Ahead Market is an hourly product and in the Real-Time Market is a five-minute product. In both markets, Supplemental Reserve is defined as the portion of MISO's Contingency Reserve requirement that is not classified as Spinning Reserve. Supplemental Reserve can be supplied in the Day-Ahead and Real-Time Markets by any Supplemental Qualified Resource, or by excess Spinning Reserve.

Q. PLEASE BRIEFLY DESCRIBE THE RAMP CAPABILITY PRODUCT.

A. MISO developed the Ramp Capability Product to provide additional operational and interchange scheduling flexibility to respond to variations in Load, and the variability of supply from intermittent sources, by maintaining sufficient ramp capability to respond to Load variations by ramping up or down to adapt to system changes.

The Ramp Capability Product reserves ramp-capable capacity for expected and unexpected Net Load variations, which can be deployed in future Dispatch Intervals when needed. The Ramp Capability Product is used in a single, five-minute Dispatch Intervals to position resources to provide for ramp capability to be available for use in future dispatch intervals. The ramp capability capacity requirement is adjusted for each interval based on historical observations of uncertainty and variability in the current demand forecasts.

MISO compensates resources that provide Up Ramp Capability and Down Ramp Capability such that Market Participants are indifferent to selling Energy, Operating Reserves, or Ramp Capability Products. Product pricing provides opportunity costs to Resources that are dispatched out of merit order in the current Dispatch Interval through the clearing of Up Ramp Capability or Down Ramp Capability in order to provide Energy or Operating Reserves in future Dispatch Intervals needed for Net Load Variability. This compensation provides economic incentives for Resources to follow dispatch so that the required ramp capability is maintained.

The key features of the Ramp Capability Product include: (1) market wide ramp capability requirements large enough to address a defined level of expected and unexpected variability in Net Load within a defined response time; (2) a ramp capability demand curve that establishes the value between using the available rampable capacity to meet current Dispatch Interval Energy and Operating Reserve requirements or holding the rampable capacity for deployment in future Dispatch Intervals; and (3) simultaneous co-optimization of ramp capability with energy and Operating Reserves.

Q. PLEASE BRIEFLY DESCRIBE THE SHORT-TERM RESERVE PRODUCT.

A. The Short-Term Reserve product was developed to enable MISO to deploy Resources capable of being deployed within thirty (30) minutes to address certain local, sub-regional, and market-wide reliability needs. By replacing MISO's previous use of out-of-market commitments for such short-term Capacity reserve needs, the Short-Term Reserve market mechanism resulted in more efficient and co-optimized commitment, deployment, and dispatch of such reserves in the Day-Ahead Market and the Real-Time Market, and prices that reflect the cost of meeting such needs, thereby reducing make-whole payment uplifts. The key features of the Short-Term Reserve product include: on-line and offline capacity eligibility, 30-minute ramp response time, co-optimization with Energy and Ancillary Services products, location-based requirements, automated deployment in Security Constrained Economic Dispatch for on-line Short-Term Reserves, and informed operator deployment for off-line Short-Term Reserves.

Q. WITHIN WHAT TIME FRAMES DO MISO'S RESERVE PRODUCTS ADDRESS UNCERTAINTY IN SYSTEM CONDITIONS?

A. MISO's reserve products address uncertainty in system conditions for the timeframes of 5 minutes to 3 hours as shown in Figure 1 below:

Product	Time Horizon	Uncertainty Addressed
Regulating Reserves	Seconds (0-5 minutes)	Uncertainty between real-time dispatch and actual load – intended for normal imbalance within 5-minute intervals
Contingency Reserves (Spin & Supplemental)	10 minutes post-contingency event	Uncertainty caused by contingencies that create significant & immediate imbalances – NERC required recovery in 15 min.
Ramp Capability Product	10-25 minutes	Uncertainty in upcoming intervals due to net load uncertainty and contingencies
Short-Term Reserve	Intra-day > 30 min, up to 3 hrs	Intra-day uncertainty caused by net load uncertainty and contingencies

Figure 1 – MISO Reserve Products Timeframes to Address Uncertainty

Q. HOW DOES MISO PRIORITIZE ITS OPERATING RESERVES?

A. Energy is the highest quality product in MISO's Day-Ahead and Real-Time Markets, and is prioritized accordingly in the co-optimized market clearing engines. Following energy, the market next prioritizes Operating Reserves, and then the Ramp Capability Products and Short-Term Reserve. Market products are prioritized through a combination of mathematical constraints, offer caps, and shortage demand curves of varying costs.

MISO's Operating Reserves consist of Regulating Reserve, and Contingency Reserves, which in turn consist of Spinning Reserve and Supplemental Reserve. These Operating Reserves have the following prioritization hierarchy: Regulating Reserve is prioritized over Contingency Reserve; and Spinning Reserve is prioritized over Supplemental Reserve. Each prioritized reserve type is deemed to be of higher value than the next reserve type(s).

Q. HOW DOES MISO ENFORCE THIS RESERVE PRIORITIZATION?

A. To implement this prioritization, "higher quality" reserves will not have lower MCPs. In terms of the reserve market clearing prices, this prioritization is reflected in the following formula: $MCP_{reg} >= MCP_{spin} >= MCP_{supp}$

When there is no shortage of "higher quality" reserves, they can be used to satisfy "lower quality" reserve requirements. The prioritization of reserves is also implemented through three cascading system-wide constraints that are enforced in the clearing engines, using the following formulas:

1. *(Reg) Reserves ≥ (Reg) Requirement*
2. *(Reg + Spin) Reserves ≥ (Reg + Spin) Requirement*
3. *(Reg + Spin + Supp) Reserves ≥ (Reg + Spin + Supp) Requirement*

The third constraint requires cleared Operating Reserves to meet the total Operating Reserve requirement. Any Operating Reserve shortage is priced through the Operating Reserve Demand Curve. The resulting Operating Reserve shortage price is reflected in the Supplemental Reserve MCP, and also in the higher quality products (Spinning Reserve, Regulating Reserve, and Energy) because of simultaneous co-optimization and its use of prioritized demand curves and cascading reserve and power balance constraints.

This prioritization is also reflected in the higher reserve product offer cap for Regulation Reserve ($500/MWh), as compared to the cap for Spinning/Supplemental Reserve ($100/MWh). In the case of MISO's other reserve products, Up-Ramp Capability does not involve offers, as prices are based on lost opportunity costs; while there are no offers for on-line Short-Term Reserve, and the cap is $100/MWh for off-line Short-Term Reserve.

Q. PLEASE DESCRIBE THE RESERVE PRODUCT DEMAND CURVES.

A. Demand Curves are used by MISO to determine the incremental value of Market-Wide Operating Reserve, Market-Wide Regulating and Spinning Reserve, Market-Wide Regulating Reserve, Market-Wide Up Ramp Capability, Market-Wide Down Ramp Capability, and Market-Wide Short-Term Reserve. Demand Curves are used in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets. These demand curves are used to establish prices when sufficient reserves are not cleared to meet the corresponding reserve requirements. Schedule 28 describes the detailed formation of these demand curves.

Q. PLEASE SUMMARIZE MISO'S EXPERIENCE WITH RECENT OPERATING RESERVE SHORTAGES.

A. The hierarchy of Regulation, Spinning and Supplemental Reserves implies that all "Operating Reserve" shortages will appear as a Supplemental Reserve shortage (the lowest quality product).

As shared in the August 2023 Market Subcommittee, between January 1, 2018, and June 23, 2023 (~5.5 years), there were 186 5-minute real-time intervals with Operating Reserve shortages. Within this period, the $200 ORDC step was removed in December 2021, and one-third of the 2022 Operating Reserve shortages occurred on December 23, 2022. Based on operational experience in last 5 to 6 years, MISO has learned that Operating Reserve Shortages are infrequent (averaging about one 5-minute interval per day) and tend to be short in nature – 87% of the shortages lasted only one or two consecutive 5-minute real-time intervals.

Figure 2 below shows that most Operating Reserve shortage intervals cleared more than 88% of the Operating Reserve requirement, and that there were no shortage intervals clearing below 50%:

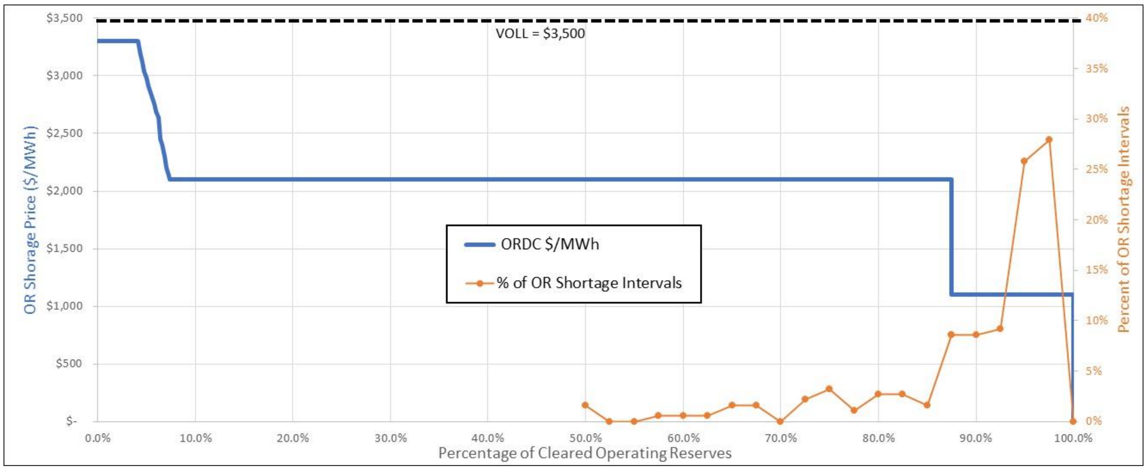

Figure 2: Frequency Distribution of Real-Time OR Shortages vs. ORDC

Q. WHAT DOES VOLL CURRENTLY REPRESENT AND HOW IS IT DEFINED IN THE TARIFF?

A. The VOLL currently represents the average cost to consumers of an interruption of firm demand under shortage conditions, as specified in Schedule 28. Currently, the Tariff defines the VOLL to be $3,500/MWh.

During periods of Operating Reserve shortages, market prices are established using the ORDC, which is influenced by the selection of the VOLL (*i.e.*, the counterpart of the proposed Pricing VOLL). As Operating Reserve shortages worsen, prices should trend towards, and ultimately approach the Pricing VOLL. In addition, the VOLL (*i.e.*, the counterpart of the proposed Pricing VOLL) is applied as the administrative price during emergency capacity.

Q. HOW IS CURRENT VOLL RELATED TO THE TARIFF'S PRICE FORMATION RULES?

A. VOLL is currently connected to four price formation elements in the Tariff:

1. Energy and Reserve Price caps (LMP and Market Clearing Price ("MCPs"));
2. Capacity Emergency load shed administrative price;
3. The top of the ORDC; and
4. EDR Offer Cap.

Figure 3 below depicts the relationship of VOLL to these elements:

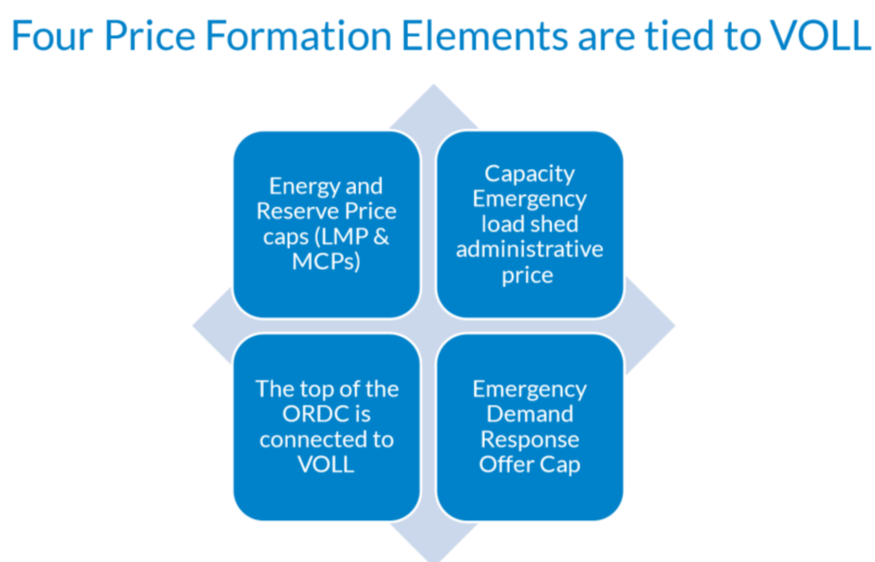

Figure 3 – Price Formation Elements Tied to VOLL

Q. PLEASE SUMMARIZE THE RATIONALE AND METHODOLOGY FOR SETTING THE ORIGINAL VOLL AT $3,500/MWh.

A. The rationale and methodology for setting the original VOLL at $3,500/MWh VOLL was based on MISO's calculation of the median values and distributions for residential, commercial and industrial customers. The $3,500/MWh value represented an estimate of the VOLL that used an average of the median values for the residential class ($1,470), and the lowest median value of the small commercial and industrial classes ($15,250). The calculation of the average used weights of 0.85 for services to the residential class, and 0.15 for service to the small commercial and industrial classes. The original VOLL value estimated the degree of "willingness to pay" of the market segment with the least valuation of uninterrupted electrical service (*i.e.*, the residential class), while also taking into account that loss of load will also impact market segments with a greater willingness to pay to avoid service interruption (*i.e.*, the small commercial and industrial classes).

MISO initially explained this rationale in 2007 as part of its filing in Docket No. ER07-1372 related to the 2009 establishment of the Ancillary Services Market. The Commission accepted MISO's methodology for setting the VOLL, and the $3,500/MWh value determined by the methodology.

IV. NEED FOR UPDATING VOLL AND ORDC

Q. WHAT ARE THE LIMITATIONS OF THE CURRENT SHORTAGE PRICING MECHANISM IN MISO?

A. Several limitations have been identified with the current MISO shortage pricing mechanism:

- As a price cap, at its current level that has not been updated since 2009, the VOLL: (a) can curtail valid market prices thereby reducing price transparency; and (b) is not sufficiently high to encourage full participation of supply and demand resources and interchange during shortage conditions.

- As an administrative price applied during MISO-directed load-shedding, the non-updated VOLL is below the industry-accepted willingness to pay, particularly according to more recent willingness to pay studies for firm loads. Because of the low cap, prices can be truncated and too low during reserve/transmission shortages.
- The current ORDC does not properly increase for greater Operating Reserve shortage and reduces congestion-management effectiveness for small Operating Reserve shortage. The ORDC is linked to VOLL, and is dominated by two fixed steps ($1,100 and $2,100). The relatively flat shape/magnitude of the current ORDC, as well as its non-updated lower/upper bounds, hampers the ORDC's ability to produce prices that appropriately reflect shortage conditions of varying degrees.

Q. HOW WOULD RETAINING THE ORIGINAL VOLL IMPACT MISO'S MARKETS IN THE FUTURE?

A. An appropriate VOLL helps to establish efficient economic signals to promote optimal interchange and generator commitments in the short-run, efficiently compensates flexible resources, and guides investment and retirement decisions in the long term. But the current understated VOLL of $3,500/MWh would not send the economic signals needed to produce these positive results.

During reserve shortage events when multiple transmission constraints are binding, the LMP price cap may be triggered. An understated LMP price cap limits visibility and transparency, as the resulting price signals will be insufficient to incent resources to increase their output. Adding new reserve products like Short-Term Reserve further restricts the room under the LMP price cap to manage congestion.

Additionally, an understated VOLL will result in market signals that do not sufficiently guide Market Participants in their longer-term decisions regarding fuel purchases, maintenance planning, power plant upgrades, power-purchase agreements, investment in demand response, and the creation and/or retention of flexible supply resources.

In summary, increasing the VOLL (*i.e.*, the current counterpart of the proposed Pricing VOLL) and adjusting the ORDC will better align shortage pricing with the marginal reliability of diminished reserve margins and curtailments of firm energy needs.

Q. HAS MISO'S INDEPENDENT MARKET MONITOR RECOMMENDED UPDATING VOLL VALUES?

A. Yes. MISO's IMM has made several recommendations and comments, starting in 2017, to improve shortage pricing by adopting an updated ORDC reflecting the expected value of lost load. Most recently, the IMM's 2023 State of the Market Report (published June of 2024) recommended that MISO, "improve shortage pricing by adopting an improved operating reserve demand curve reflecting the expected value of lost load."[4] Highlighting the importance of this recommendation, the IMM's report states that this effort should be one of MISO's highest priorities since it is critical for achieving the goals of the Reliability Imperative.[5] The IMM's affidavit in support of this filing provides more detail on its recommendation and associated benefits.

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[4] *See 2023 State of the Market Report for the MISO Electricity Markets* at p. 100 - https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf

[5] *Id.* at p. 101.

Q. HOW HAS MISO RESPONDED TO THE IMM'S RECOMMENDATIONS?

A. MISO agrees with the IMM's description of this issue and generally supports the IMM's proposed solution. Initial review and planning for the proposed VOLL and ORDC updates started in late 2019. MISO filed in October 2019 to accelerate implementation of FERC Order No. 831, which increases the Energy Offer Cap to $2,000 or above and introduced a third step to MISO's ORDC at $2,100/MWh above the then existing second step ($1,100/MWh) and first step ($200/MWh) for less severe reserve shortages.

MISO began reviewing several aspects of shortage and emergency pricing with stakeholders in 2020.[6] MISO published a Scarcity Pricing Evaluation Paper in May 2021. Key items evaluated in the paper included: (1) the IMM's methodology to create the loss-of-load probability curve for different reserve levels and proposed modifications; and (2) establishing a reasonable cost of shedding firm load (*i.e.*, the VOLL).

In 2021, MISO filed with FERC to remove the first $200 step of the ORDC to align with the costs of emergency actions taken to avoid Operating Reserve shortages.

MISO had previously researched and vetted VOLL estimation methods with the stakeholder community, but additional discussions were necessary before making changes.[7] While MISO agreed that the current VOLL is dated and needs assessment and possible revision, MISO carefully developed the chosen method for calculating VOLL to

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[6] *See* MISO Dashboard: MSC-2019-1 Continued Reforms to Improve Scarcity Pricing and Price Formation, available at: https://www.misoenergy.org/engage/MISO-Dashboard/continued-reforms-to-improve-scarcity-pricing-and-price-formation/.

[7] *See* Value of Lost Load (VOLL) Scarcity Pricing Evaluation presentation, MISO Workshop (January 22, 2021), available at: https://cdn.misoenergy.org/20210122%20Scarcity%20Pricing%20Evaluation%20Workshop%20Item%2005%20Value%20of%20Lost%20Load514792.pdf.

ensure that its approach to updating the VOLL calculation would be credible, defensible, and transparent.

In 2023, MISO focused on designing a solution for the market pricing of Forced-Off Assets ("FOA") resulting from forced transmission outage situations. The Tariff's FOA revisions were filed on February 5, 2024, and accepted by the Commission on May 31, 2024.

Given the potentially significant market impacts to stakeholders of any changes made to the VOLL value, prudence dictated that MISO adopt a thorough methodological approach that required time to assess, collaborate on, and implement stakeholder discussions on the VOLL and ORDC updates began in the second half of 2023 and culminated in the development of the Tariff changes proposed in this filing. These stakeholder discussions are summarized in the testimony of Mr. Todd Ramey.

Q. WILL THE IMM CONTINUE ITS FUNCTIONS REGARDING THE MONITORING AND MITIGATION OF PHYSICAL WITHHOLDING UNDER SHORTAGE CONDITIONS?

A. Yes. The proposed Tariff revisions do not affect the Tariff's existing Module D provisions on the IMM's monitoring of potential physical withholding during shortage conditions pursuant to section 53.1A, and the mitigation of any such conduct pursuant to section 64.1.1.

V. APPLICATION OF ADMINISTRATIVE VOLL PRICING DURING EEA – LEVEL 3

Q. WHAT IS AN ENERGY EMERGENCY ALERT OR "EEA"?

A. NERC defines Energy Emergency Alerts ("EEAs") in Attachment 1 to the Emergency Operations standard EOP-011-4 as follows: "(a)n EEA is an Emergency Procedure, not a daily operating practice …" The Reliability Coordinator ("RC") will notify other neighboring RCs and the Balancing Authorities in the RC's area that one or more of the Balancing Authorities is energy deficient. The RC may use the relevant alert level and does not need to go sequentially through the EEA levels.

Q. PLEASE DESCRIBE MISO'S CAPACITY SHORTAGE EMERGENCY PROCEDURES.

A. The MISO Market Capacity Emergency Procedure is used to address Capacity Shortages and is posted on MISO's website.[8] Figure 4 further below shows several stages in the procedure. The procedure describes entry conditions for the Capacity Advisory (first row of Figure 4), Maximum Generation ("Max Gen") Alert (second row), Max Gen Warning (third row) and Max Gen Event (fourth and ensuing rows). After entry conditions, the actions taken by MISO and stakeholders are described in each step. The last topic of discussion includes the steps to exit the maximum generation event (last row). When Operating Reserve becomes or is forecasted to become short, MISO will move from a maximum generation alert to a maximum generation warning. To commit emergency resources, MISO will move to a maximum generation event as shown in Figure 4 below (fourth row, "Event Step 1"). As the event progresses, Load Modifying Resources,

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[8] *SO-P-EOP-00-002 Rev 20 MISO Market Capacity Emergency*, effective 06/01/2024.

Emergency Demand Resources and Emergency Energy Purchases are implemented. The last step, Max Gen Event Step 5 (EEA – Level 3), results in firm load shed.

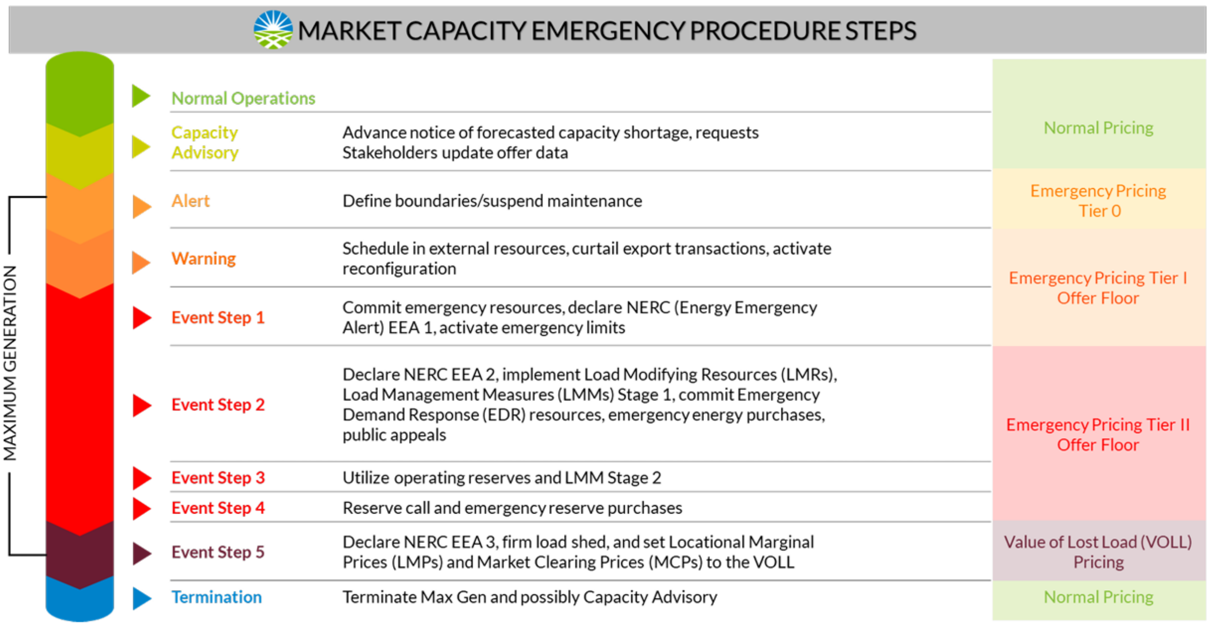


Figure 4 – Market Capacity Emergency Procedure Steps

Q. HOW DOES SHORTAGE PRICING RELATE TO EXISTING EMERGENCY OPERATING PROCEDURES?

A. The MISO Market Capacity Emergency Procedure (SO-P-EOP-00-002 Rev 20) provides Figure 4 above as a summary of Market Capacity Emergency Procedure Steps, including the Max Gen steps leading up to firm load-shedding (EEA – Level 3).

The MISO emergency pricing construct uses Extended Locational Marginal Pricing ("ELMP") to better reflect system needs during Max Gen Emergencies.

Beginning at the Max Gen Alert level (second row of Figure 4), MISO implements Emergency Pricing Tier 0, which allows ELMP to adjust prices to include the commitment costs for Emergency Operations Resources, which have up to four-hour start-up times and minimum run times of less than four hours.

At higher Max Gen levels, MISO establishes Emergency Offer Floors ("EOFs") to assign Proxy Offers for Emergency resources, to prevent price suppression within ELMP. Relevant Emergency resources include External Resources that qualify as Planning Resources, Generators' Emergency Capacity, Load Modifying Resources, Emergency Demand Response Resources and Emergency Energy Purchases.

At the Max Gen Warning level (third row of Figure 4), the Tier I EOF is established as the minimum of $500 or the highest available economic offer in the Energy Emergency Area. At the Max Gen Event Step 2 level, the Tier 2 EOF is established as the minimum of $1000 or the highest available economic or emergency offer in the Energy Emergency Area. As a further bulwark against price suppression, Tier II accounts for the possibility that an Emergency Offer may be higher than an economic Offer due to Emergency dispatch range release.

The ORDC operates throughout the progression of the Emergency Procedure, as prices rise towards VOLL in proportion to the severity of shortage conditions. In Step 5 (penultimate row of Figure 4), the Pricing VOLL is applied as an administrative price as shortage conditions reach the highest degree of severity.

Q. HOW DO NERC EEA LEVELS RELATE TO THE MISO EMERGENCY PROCEDURE STEPS?

A. NERC Emergency Event Alert (EEA) – Level 1 aligns with Max Gen Event Step 1. EEA – Level 2 aligns with Max Gen Event Steps 2, 3, and 4. EEA – Level 3 aligns with Max Gen Event Step 5. Figure 5 below highlights this alignment.

MISO's operating procedures ensure reliability during emergency or abnormal operating situations

Conservative Operations: If conditions warrant, MISO will transition from normal operating conditions to Conservative Operations to prepare local operating personnel for a potential event, and to prevent a situation or event from deteriorating	
Emergency Operations: Emergency Operating Procedures (EOPs) guide system operator actions when an event occurs on the electric system that has the potential to, or actually does, negatively impact system reliability. EOPs are communicated in escalating order as alerts, warnings, and events	
Cold or Hot Weather Alert	Extreme temperatures forecasted
Severe Weather Alert	Adverse weather conditions within the area
Conservative Operations Declarations	Reliability issues may be possible
Maximum Generation Alert	MISO forecasts a potential capacity shortage
Maximum Generation Warning	Preparing for a possible event
Maximum Generation Event (Step 1) / EEA*1	Taking steps to preserve operating reserves
Maximum Generation Event (Steps 2, 3, 4) / EEA*2	Taking steps to preserve firm load
Maximum Generation Event (Step 5) / EEA*3	Actual event occurring - shed firm load and/or perform rolling brownouts or blackouts for defined area

Figure 5 - Relationship between Emergency Operation Procedure and NERC Emergency Energy Alert

Q. PLEASE DESCRIBE THE PROCESS WHEN MISO DIRECTS A LOCAL BALANCING AUTHORITY TO SHED LOAD.

A. In MISO Market Capacity Emergency SO-P-EOP-00-002, the Shift Manager will declare Maximum Generation Event Step 5 and EEA – Level 3. Manual load shedding requirements are determined for the impacted Local Balancing Authorities ("LBAs") in the declaration area. MISO communicates the Emergency Operating Instructions to the LBAs in the declaration area, including the MW amount of load to shed. The LBA takes action to curtail the requested MW amount of load.

During Emergency conditions where Load Shedding is instructed by MISO, Real-Time Ex Ante LMPs, Real-Time Ex Ante MCPs, Real-Time Ex Post LMPs, and Real-Time Ex Post

Operating Reserve MCPs will be set to the VOLL, either on a MISO Balancing Authority Area basis or Sub-Area basis, as applicable, until the Emergency condition is no longer in effect.

VI. PROPOSED VALUE OF LOST LOAD

Q. WHAT VOLL DOES MISO PROPOSE?

A. MISO proposes to distinguish two kinds of VOLL: (1) a Pricing VOLL of $10,000/MWh to be used as a price cap and an administrative price; and (2) a System VOLL of $35,000/MWh to be used to scale the ORDC.

Q. WHY IS MISO PROPOSING TWO DIFFERENT VOLL VALUES?

A. The two VOLL values have different functions. The Pricing VOLL represents the price consumers are willing to pay to avoid an interruption of electrical service, and is mainly based on consumers with the lowest willingness to pay. This Pricing VOLL is appropriate to use as a price cap (at all times) and also for fixed administrative pricing in EEA-Level 3 energy shortage conditions.

The System VOLL represents the composite price that consumers are willing to pay to avoid an interruption of electrical service. It is appropriate for scaling the Loss of Load Probability Curve for use in the Operating Reserve Demand Curve. The slope of the ORDC reflects the increased probability of losing load as the level of operating reserves falls. Determining the probability of losing load depends on the combinations of random contingencies along other factors, including wind, load, and NSI uncertainties.

The updated values will ensure that MISO's shortage pricing rules maintain and enhance compliance with the Commission's requirement that shortage prices reflect load's willingness to pay to avoid service interruption under shortage conditions.

Q. WHY IS $10,000/MWh A REASONABLE VALUE FOR THE PRICING VOLL?

A. As discussed above, MISO proposes a Pricing VOLL of $10,000/MWh as a price cap, and for administrative pricing during MISO-directed EEA – Level 3 load-shed events.

$10,000/MWh is a low-end estimate of the negative financial impacts associated with MISO-directed firm load-shedding. Because residential load has a markedly lower VOLL than commercial and industrial loads, LBAs often prioritize it earlier in their load-shedding plans.

This valuation recognizes that, while load shedding will be focused on the residential class, which has a 1-hour-outage Summer VOLL of $4,337/MWh, other load classes will inevitably be curtailed during such an event. As such, even adding 15% of non-residential load would result in a VOLL of $13,640MWh. And if load was shed equally across all load types, that would support a VOLL of $36,888/MWh.

The proposed Pricing VOLL of $10,000/MWh allows market prices to exceed the Willingness To Pay ("WTP") threshold for many loads, providing a clear financial incentive to reduce consumption. In addition, this proposal is reasonable because it will incentivize the availability of incremental emergency supply from resources and interchange.

In addition, the proposed VOLL of $10,000/MWh, combined with the redesigned ORDC, provides room for all pricing components (*e.g.*, Marginal Energy Component, Marginal

Congestion Component, and Marginal Loss Component) before price capping. See Figure 6 below.

Ultimately, MISO determined that the values in excess of the proposed $10,000/MWh as Pricing VOLL would be excessive given the potential financial impact of extended VOLL-pricing. In that vein, MISO is further proposing that, when the shortage conditions that result in the application of the Pricing VOLL as an administrative price last for an extended period, the Pricing VOLL will be reduced proportionately through "circuit breaker" rules, which are discussed in more detail later in my testimony.

Q. WHAT DID MISO CONSIDER WHEN DETERMINING THE $10,000/MWh VALUE FOR THE PRICING VOLL?

A. MISO explored several ways of developing an updated VOLL from the latest data. For example, the data could be calculated to produce a weighted 1-hour Summer VOLL of $36,888/MWh. Alternatively, a VOLL of $13,640/MWh would result if MISO were to apply the same load class weights used for the current $3,500/MWh VOLL.

On the one hand, MISO residential load comprises 35% of the total load and has a markedly lower VOLL than commercial and industrial loads, and so it should be, and typically is, the primary target for MISO directed and LBA-administered load-shedding. On the other hand, some non-residential loads will inevitably be shed along with residential loads. Balancing these two considerations, MISO concluded that $10,000/MWh is a reasonable and appropriate value for the Pricing VOLL that will generate appropriate pricing signals without being punitive.

Q. WHAT ARE THE ADVANTAGES OF THE PROPOSED PRICING VOLL?

A. The proposed Pricing VOLL has several advantages.

First, it provides a more transparent price signal because it is based on, and better accounts for, updated Willingness to Pay data for key load classes, and aligns with MISO's market design principle that prices reflect marginal system costs.

Second, it allows market prices to exceed the willingness to pay threshold for many loads, providing a financial incentive to reduce real-time consumption.

Third, this Pricing VOLL is a large enough price signal to incent incremental emergency supply from all resource types, as well as interchange with our neighbors, and aligns with MISO's market design principle that prices should enhance the ability of Market Participants to make efficient operational and investment decisions. This level of potential real-time VOLL pricing will also encourage greater participation and hedging in the Day-Ahead Market, particularly when tight operating conditions are anticipated.

Fourth, this Pricing VOLL, combined with an appropriately designed ORDC, provides room for all pricing components, including Marginal Energy Component ("MEC"), Marginal Congestion Component ("MCC") and Marginal Loss Component ("MLC") to function before prices are capped. MEC would effectively be capped (~$8,700 - $9,000/MWh) considering all demand curves and offer caps. The following figure illustrates that the maximum MEC for the proposed ORDC is ~$8,800/MWh, assuming a Regulating Reserve Demand Curve of $200.

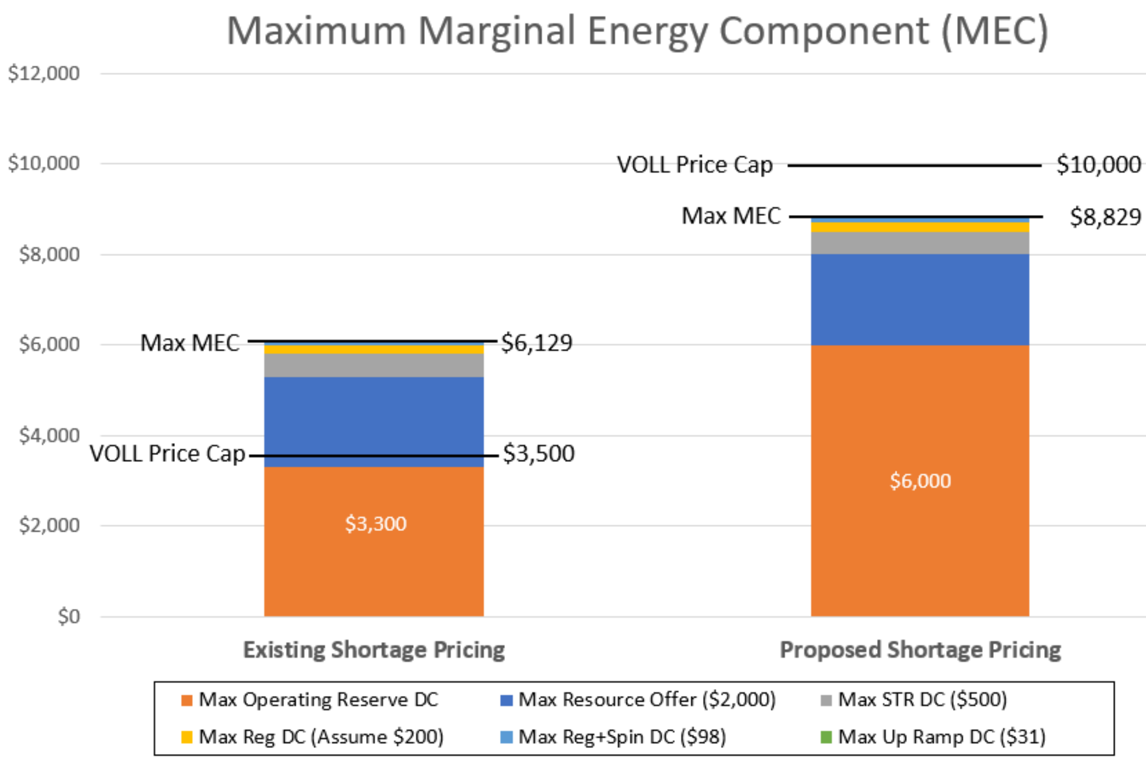


Figure 6 – Illustration of Maximum MEC

Fifth, it avoids setting prices too high, which would expose Market Participants to greater financial risk during periods of extended VOLL pricing.

Q. WHAT METHODOLOGY DID MISO USE TO UPDATE VOLL VALUES?

A. MISO used the same methodology to update VOLL values as the one that FERC accepted for MISO's original VOLL. That methodology remains fundamentally sound, and MISO sees no reason to depart significantly from its core framework. MISO updated the willingness to pay data, and verified the reasonableness of the consumer class weightings. At the end of 2023, MISO updated VOLL calculations using recent econometric results, delineating multiple load characteristics and willingness to pay data. These analyses utilized the Lawrence Berkley National Laboratory meta-analysis with MISO specific drivers, consistent with the approach MISO used in its original determination of VOLL, and the IMM's recommendations. This approach uses two-step regression models to estimate statistically significant outage cost functions. As a result of the analysis, hundreds of values for VOLL were updated, with breakdowns for the following aspects where the highest VOLL factors are bolded in Figure 7 below:

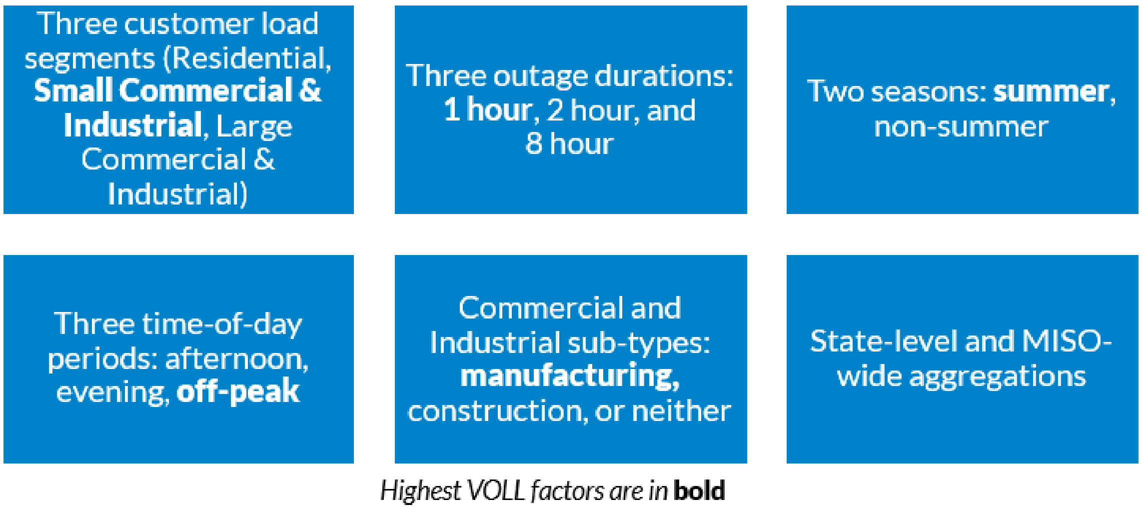


Figure 7 – Breakdown of highest VOLL factors

MISO tempered the recommended VOLL valuations to avoid any excessive financial burdens of shortage pricing on Market Participants, while aiming for price signals that will properly reflect shortage conditions and the cost of addressing them.

Q. WHAT ARE THE NOMINAL VALUES RESULTING FROM THIS ANALYSIS?

A. The nominal values are reported on a load class basis across five outage durations. As the outage duration increases, the nominal values decrease on a $/MWh basis. This demonstrates that certain negative financial consequences occur at the start of firm load curtailment.

The System nominal value is calculated using a load weighting of 34% for Large Commercial and Industrial, 31% for Small Commercial and Industrial, and 35% for Residential. The 2023 MISO-wide, load weighted nominal values resulting from the updated analysis are provided in Figure 8 below:

2023 MISO-wide VOLL ($/MWh) components for key load classes and outage durations

Load Class	1-hr outage	2-hr outage	4-hr outage	8-hr outage	12-hr outage
Residential	$4,337	$2,420	$1,477	$1,013	$832
Small C&I	$80,965	$50,277	$37,006	$33,271	$31,098
Small C&I, Services #	$66,354	$41,227	$30,328	$27,267	$25,486
Large C&I	$29,472	$20,391	$18,194	$21,859	$24,054
System *	$36,889	$23,545	$18,342	$18,309	$18,342
System VOLL using 2007 weightings (85% Residential / 15% Services)	**$13,639**	**$8,241**	**$5,804**	**$4,951**	**$4,530**

Basis of $10,000 VOLL for EEA events < 4 hrs

Basis of $5,000 VOLL for EEA3 events >=4 hrs

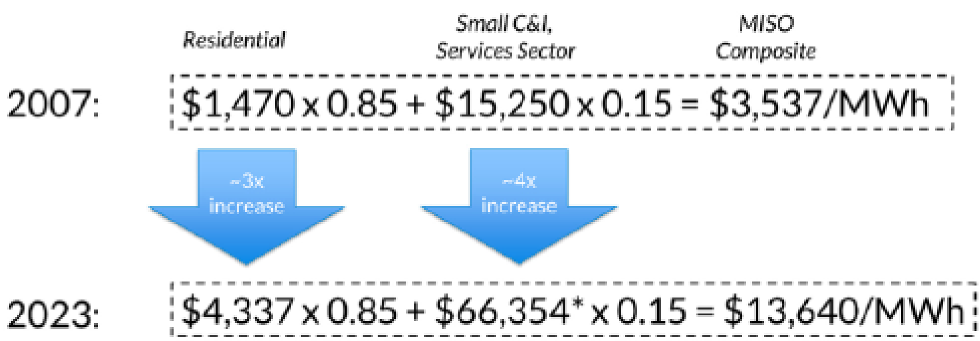
 # Value reduced by 18% if only considering "Services" sub-category of Small C&I
** Inter-class weights: 34% Large C&I, 31% Small C&I, 35% Residential*

Figure 8 – MISO-wide VOLL Components for Key Load Classes

The final row of this table uses an 85% weighting factor for Residential load class and a 15% weighting factor for the services sector of the small Commercial and Industrial load class. The one-hour and two-hour outage values are the basis for the recommended $10,000 Pricing VOLL.

Q. WHAT WOULD BE THE RESULT OF SIMPLY UPDATING THE 2007 VOLL COMPONENTS (i.e., VOLL VALUE CORRESPONDING TO SUMMER, 1-HOUR OUTAGE, OFF-PEAK) TO 2023 VALUES?

A. The VOLL value based on nominal values corresponding to Summer, 1-Hour outage, Off-peak condition was proposed by MISO for the creation of the Ancillary Service Market, which FERC accepted. Updating the 2007 VOLL components (Summer, 1-Hour outage, Off-peak) to 2023 values would support a VOLL increase in the range of 300-400%, *i.e.*, to $13,640/MWh. This is shown in the following calculation in Figure 9 below:



** MISO estimated the Services sector value, which was utilized in the 2007 VOLL calculation.*

Figure 9 – Calculation of VOLL in 2007 vs. 2023

As noted earlier, however, MISO assessed that $10,000/MWh is a reasonable and appropriate value for the Pricing VOLL, as it will generate appropriate pricing signals and avoid being punitive.

Q. DID UPDATING THE VOLL NECESSITATE ANY ANALYSIS OF SPECIFIC COSTS AND BENEFITS TO CONSUMERS?

A. No, a traditional cost-benefit analysis is unnecessary in this instance because the VOLL is fundamentally based on, and tied to, the willingness of various load classes to pay for uninterrupted service. That is why it is called VOLL, as it literally consists of the value that load places on losing service. This was the market-based methodology that MISO proposed, and FERC accepted, for the original VOLL of $3,500/MWh, and is the same methodology MISO used for updating the VOLL, by using updated willingness to pay data. This market-based approach ensures that prices will reflect loss of load valuations so that the resulting market price signals will incent increased supply and reduced demand during shortage conditions. The VOLL framework was also accepted by the Commission in Order No. 719, and preceding price formation workshops. It is also noteworthy that Order No. 719 did not accept suggestions to broadly condition RTO/ISO tariff changes on any detailed cost-benefit analysis.

Q. HOW WILL MISO'S PROPOSAL INCENT MARKET PARTICIPANT BEHAVIOR IN THE REAL-TIME MARKET?

A. In the Real-Time Market, the proposed shortage pricing rules will incent increased supply and reduced demand, thereby restoring or improving the supply/demand balance. Over time, MISO anticipates the updated Pricing VOLL will also encourage the development of additional demand flexibility and price-responsiveness in the Real-Time Market.

Q. HOW WILL MISO'S PROPOSAL INCENT MARKET PARTICIPANT BEHAVIOR IN THE DAY-AHEAD MARKET?

A. The updated shortage pricing rules will also encourage Market Participants to participate in the Day-Ahead Market to hedge real-time shortage pricing risks, and allow the market to economically provide needed supply. Greater Day-Ahead Market participation by loads allows MISO to economically commit additional longer-lead time resources, and to schedule additional imports into the footprint. This allows the MISO market to meet the real-time energy needs both economically and reliably, and reduces the likelihood of energy shortage conditions.

Finally, by removing the Price-Sensitive Demand Bid Cap, Demand will be able to bid their willingness to pay, which may be greater than $2,000/MWh and less than the proposed $10,000/MWh Pricing VOLL.

Q. HOW WILL MISO'S PROPOSAL INCENT MARKET PARTICIPANT BEHAVIOR IN THE LONGER-TERM?

Beyond the Day-Ahead Market incentives, appropriate shortage prices can signal Market Participants to improve strategies on the weekly, monthly and yearly timeframes. While these effects are secondary/tertiary in nature, they are directionally consistent with other longer-term market forces, such as the Planning Resource Auction. Longer-term strategies include outage scheduling, fuel contracting, winterization/maintenance efforts, and the creation and/or retention of flexible supply resources and demand response technologies.

Q. HOW CAN MARKET PARTICIPANTS MANAGE PRICING RISKS ASSOCIATED WITH THE PROPOSED SHORTAGE PRICING?

A. The objective of MISO's shortage pricing reforms is to send appropriately high price signals during periods of severe supply inadequacies, so that Market Participants can then identify and implement strategies to minimize their own financial risks. These strategies will depend on the Market Participant type (*e.g.*, supply, demand, interchange), as well as their individual risk profile. MISO does not favor any specific solution approach or Market

Participant type, and expects a combination of such risk reduction measures will improve the ability of the market to reliably (and affordably) deliver energy to consumers.

In particular, Market Participants can hedge the risks of real-time shortage prices by increasing their real-time flexibility of energy supply/consumption during periods of high shortage prices, increasing participation in the Day-Ahead Market to procure sufficient energy for the upcoming Operating Day, entering into long-term financial contracts (*e.g.*, power purchase agreements, financial hedging), or through portfolio management. Such strategies will reduce the number and/or severity of energy and reserve shortage conditions.

Q. HOW WILL THE PROPOSED CHANGES TO THE SHORTAGE PRICING RULES AFFECT THE RELATIONSHIP OF THE VOLL TO THE FOUR PRICE FORMATION ELEMENTS DISCUSSED EARLIER?

A. The figure below illustrates how the proposed shortage pricing changes will modify the relationship between the VOLL and the four price formation elements:

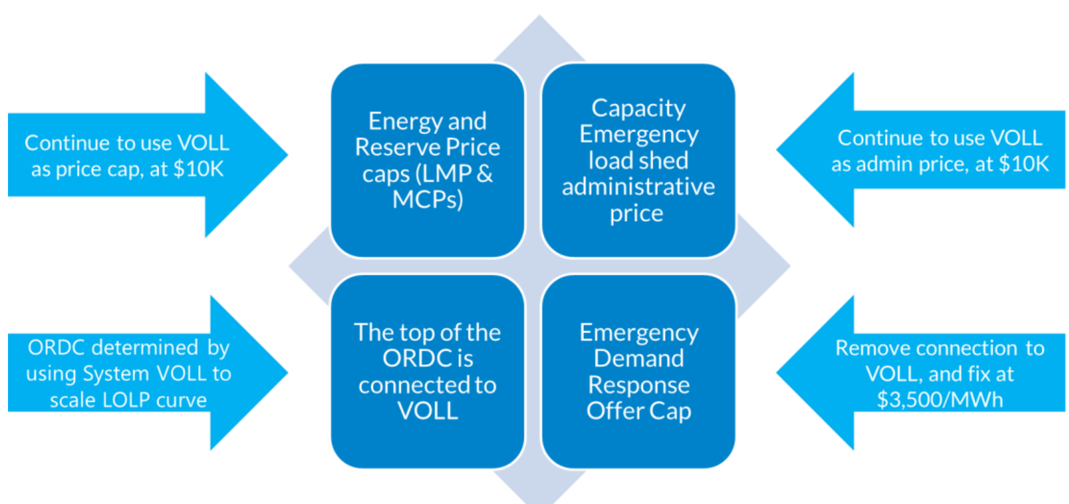


Figure 10 – Relationship of VOLL to Pricing Elements

Under MISO's proposal, the Pricing VOLL will continue to be used as a price cap, and as an administrative price during Energy Emergency Alert – Level 3 events with Load Shedding.

- LMP cap and Market Clearing Price ("MCP") cap: The Tariff defines the LMP cap and MCP cap to be VOLL in the Ex-Ante and Ex-Post processes. If reserve requirements are not fully satisfied, while several transmission constraints are binding, the LMP may naturally exceed VOLL. The LMP and MCP caps serve as a backstop to prevent excessive market prices.
- Administrative Capacity Emergency Load-Shed Price: During the last step of a capacity emergency event, MISO will issue an Energy Emergency Alert (EEA – Level 3) to warn that load shed is imminent. Once load is shed, market prices would likely reduce as the available supply is now able to meet the load. However, these lower prices do not reflect the incremental cost of the desired demand (*i.e.*, non-interrupted demand). MISO will administratively set the LMPs and MCPs to VOLL across the MISO Balancing Authority Area or Sub-Area for the duration of the load shed event.

The System VOLL will be used to scale the Loss of Load Probability Curve to determine the Operating Reserve Demand Curve. VOLL will no longer constitute the EDR Offer Cap, which instead will be set at the specific amount of $3,500/MWh (*i.e.*, the amount of the existing VOLL).

Q. WHY IS MISO ALSO PROPOSING THAT THE ENERGY OFFER HARD PRICE CAP OF $2,000/MWH NO LONGER BE APPLIED AS A CAP ON DAY-AHEAD PRICE-SENSITIVE DEMAND BIDS AND VIRTUAL DEMAND BIDS?

A. MISO considers it unnecessary and inappropriate to apply the Energy Offer Hard Price Cap to Day-Ahead Price-Sensitive Demand Bids and Virtual Demand Bids. The cap was applied as part of the momentum in complying with Order No. 831, but was not required by Order No. 831. Before Order No. 831, there were no day-ahead bid caps in the MISO Tariff. The application of this bid cap prevents Day-Ahead Price Sensitive Demand from specifying a value between $2,000/MWh and VOLL. In contrast, Fixed Demand Bids will clear at any price, up to the existing VOLL. There is no viable policy reason not to allow Day-Ahead Price Sensitive Demand to likewise bid beyond the $2,000/MWh price cap.

The present filing's proposal to increase the VOLL is an opportune time to remove the Energy Offer Hard Price Cap for Price Sensitive Demand Bids and Virtual Demand Bids. Removing the bid cap would allow day-ahead demand to specify a maximum bid price above $2,000/MWh.

Q. HOW WILL COLLATERAL REQUIREMENTS BE HANDLED WHEN THE PROPOSED SHORTAGE PRICING IS TRIGGERED BY EXTREME WEATHER EVENTS?

A. When extreme weather events trigger the proposed shortage pricing, collateral requirements will be handled pursuant to recent Tariff revisions that give MISO the option to use "best available information" to determine the appropriate collateral requirements during extreme weather/pricing events. Those Tariff revisions were prompted by MISO's experience with Winter Storm Uri, which was an extreme weather event that would have otherwise resulted in excessive collateral requirements. MISO requested, and FERC granted, a Tariff waiver that enabled MISO to use the "best available information" to determine the collateral requirements. Afterwards, MISO made a FERC filing to incorporate this option into the Tariff.

The Tariff changes that allow MISO to use the "best available information" for collateral requirements were put in place because, although MISO's Day Ahead-Real Time ("DART") calculations work well under normal weather conditions, during a short-term extreme weather event that can trigger shortage pricing, MISO Market Participants may experience excessive collateral requirements that last up to two weeks after the event occurs. The current calculations use a rolling average based upon the greater of either a 365-day or a 7-day "look-back" on the value specified in the S7 (*i.e.*, the Settlement Statement issued seven days after an Operating Day). During an event, when prices spike, the collateral requirement typically switches to the 7-day rolling average, which amplifies an event's impacts on collateral requirements; whereas, when an event is captured in a 365-day rolling average, the financial impact of the event is diluted. When an extreme weather event triggers shortage pricing in such a way that the DART calculation's use of the 7-day rolling average would result in excessive collateral requirements, MISO now has the option to use the "best available information" to determine more appropriate collateral requirements.

The collateral requirements can be adjusted only for physical day-ahead or real-time transactions. By using "best available information," MISO would provide collateral financial relief to Market Participants during extreme events.

VII. NEED AND DEVELOPMENT OF A PRICING VOLL CIRCUIT BREAKER

Q. WHAT HAS DRIVEN THE NEED FOR CIRCUIT BREAKERS FOR THE PRICING VOLL?

A. Although EEA – Level 3 events lasting more than a few hours are unlikely based on experience and planning studies, the proposed increase in the pricing VOLL prompted some stakeholder and state commission concern about the significant financial risks Market Participants may face in the event that shortage conditions somehow last long and the high prices do not lead to changes in behavior. MISO considers it prudent and reasonable to respond to such stakeholder concerns by establishing mechanisms to mitigate the financial impacts of long-duration shortage conditions, even if they may be rare. Higher potential prices (higher price cap) increase the importance of such safeguards, which are warranted because costs (per MWh) drop for longer load-shed or shortage events.

Accordingly, MISO developed a Pricing VOLL Circuit Breaker ("CB"). A Pricing VOLL CB would limit excessive market risk resulting from high prices over an extended period of shortage pricing. The MISO recommended VOLL and ORDC changes are appropriate for short-term Operating Reserve and/or energy shortages, lasting minutes-to-hours. For extended-duration energy shortage events lasting hours-to-days, the Pricing VOLL CB will mitigate financial risks.

To date, MISO has not experienced market conditions that would have invoked application of a shortage pricing circuit breaker as proposed herein. Nevertheless, out of an abundance of caution, and in response to stakeholder concerns, MISO is proposing to proactively establish a shortage pricing circuit breaker so that appropriate rules are in place if shortage conditions that trigger application of the Pricing VOLL last longer than expected.

Q. PLEASE DESCRIBE THE CIRCUIT BREAKER MECHANISM THAT MISO IS PROPOSING FOR THE PRICING VOLL.

A. MISO is proposing a circuit breaker mechanism that will lower the Pricing VOLL gradually when shortage conditions persist, in order to moderate the financial impacts of extended shortage conditions.

In particular, MISO proposes the following circuit breakers.

- First, at the end of four hours of real-time EEA – Level 3 load-shedding in a Max Gen Emergency, the real-time Pricing VOLL shall be reduced to $5,000/MWh.
- Second, when the shortage conditions that led to a Max Gen Emergency with EEA – Level 3 persist in the Real-Time Market when the Day-Ahead Market closes at 1030 Eastern Prevailing Time ("EPT"), the day-ahead and real-time Pricing VOLLs shall be reduced to $5,000/MWh for the next Operating Day.
- Third, when the shortage conditions that led to the Max Gen Emergency continues to any additional Day-Ahead Market closing, the day-ahead and real-time Pricing VOLLs shall be reduced to $2,000/MWh for the next Operating Day.

Q. PLEASE EXPLAIN THE RATIONALE FOR THE FIRST CIRCUIT BREAKER.

A. The initial real-time Pricing VOLL of $10,000/MWh is appropriate for the first 4 hours of EEA – Level 3 load-shedding within a single Max Gen Emergency, because it establishes prices commensurate with forced load-shedding, incentivizing Day-Ahead Market participation, emergency supply and demand response, captures ~85% of expected unserved energy events, based on updated loss of load expectation studies. However, when the shortage conditions that led to an EEA – Level 3 event exceeds four hours, it is reasonable and necessary to reduce the Pricing VOLL. The first circuit breaker reduces the real-time Pricing VOLL to $5,000/MWh after four hours. This reduction is appropriate because average outage costs are lower past the fourth hour of an EEA – Level 3 emergency, based on updated VOLL studies. In particular, the studies show that in outages lasting 4-12 hours, outage costs were consistently in the $5,000/MWh range, as highlighted in the figure below. This reduction also captures ~15% of expected unserved energy events, as shown in updated loss of load expectation studies.

2023 MISO-wide VOLL ($/MWh) components for key load classes and outage durations

Load Class	1-hr outage	2-hr outage	4-hr outage	8-hr outage	12-hr outage
Residential	$4,337	$2,420	$1,477	$1,013	$832
Small C&I	$80,965	$50,277	$37,006	$33,271	$31,098
Small C&I, Services #	$66,354	$41,227	$30,328	$27,267	$25,486
Large C&I	$29,472	$20,391	$18,194	$21,859	$24,054
System *	$36,889	$23,545	$18,342	$18,309	$18,342
System VOLL using 2007 weightings (85% Residential / 15% Services)	**$13,639**	**$8,241**	**$5,804**	**$4,951**	**$4,530**

Basis of $10,000 VOLL for EEA events < 4 hrs

Basis of $5,000 VOLL for EEA3 events >=4 hrs

 # Value reduced by 18% if only considering "Services" sub-category of Small C&I
** Inter-class weights: 34% Large C&I, 31% Small C&I, 35% Residential*

Figure 11 - Decrease in MISO-wide VOLL for longer outages supports Circuit Breaker breakpoint

Q. PLEASE EXPLAIN THE RATIONALE FOR THE SECOND CIRCUIT BREAKER.

A. After the shortage conditions that led to an EEA – Level 3 event lasts more than 12 hours, it is appropriate to further reduce the Pricing VOLL to $2,000/MWh because at that point, it is even less necessary to maintain a high shortage price for reliability purposes. The second circuit breaker value of $2,000/MWh is consistent with the Energy Offer Hard Price Cap established pursuant to Order No. 831. Such pricing would remove the potential need to make uplift payments for generator offers reaching the offer cap.

Q. HOW WILL THE CIRCUIT BREAKERS APPLY IF THERE ARE SEVERAL EEA – LEVEL 3 PERIODS WITHIN A SINGLE DECLARED MAX GEN EMERGENCY?

A. Where there are multiple EEA – Level 3 periods within a single declared Max Gen Emergency, the cumulative EEA – Level 3 time determines the first circuit breaker transition to the lower real-time Pricing VOLL value.

Even if the Max Gen Emergency is declared for only a portion of the MISO market, these Pricing VOLL circuit breakers will be applied across the entire market (*i.e.*, there is a single real-time Pricing VOLL, which is used as both a market-wide price cap and as the administrative price applied during EEA3 conditions of a declared Max Gen Emergency).

Q. WHEN WILL THE DAY-AHEAD AND REAL-TIME PRICING VOLLS CEASE TO BE APPLIED AS AN ADMINISTRATIVE PRICE FOLLOWING THE ACTIVATION OF A PRICING CIRCUIT BREAKER DURING EXTENDED EEA – LEVEL 3 CONDITIONS?

A. When the day-ahead and/or real-time Pricing VOLLs have been reduced by a circuit breaker, they shall cease to apply after MISO has terminated the Max Gen Emergency. At that point, the Pricing VOLL, as a potentially applicable administrative price, shall be reset to $10,000/MWh. Furthermore, if the Max Gen termination occurs before 1030 EPT, the day-ahead and real-time Pricing VOLLs, as potentially applicable administrative prices, are reset to $10,000/MWh at the end of the current Operating Day. If the Max Gen termination occurs after 1030 EPT, the Pricing VOLLs, as potentially applicable administrative prices, are reset to $10,000/MWh at the end of the next Operating Day.

Q. PLEASE PROVIDE EXAMPLES OF HOW THE PRICING VOLL'S INITIAL VALUE WOULD BE RESET IN SITUATIONS WHERE THE CIRCUIT BREAKERS ARE APPLIED.

A. The following example was presented at the July and August 2024 Market Subcommittee meetings. It illustrates how the Day-Ahead and Real-Time Pricing VOLL values would change for an extreme load-shedding event lasting more than a single day.

Scenario: A Max Gen Emergency is declared at 0200 on Day 1, escalating to EEA – Level 3 (Max Gen Event Step 5) at 0800. The MISO-directed load-shedding lasts 24 hours (ends Day 2 0800). The Max Gen Emergency lasts 12 more hours, before it is "terminated" by MISO Operations at 2000 on Day 2. Note that RT and DA pricing will be impacted for three days.

DAY 1

0200: In RT, a MISO declares a Max Gen Emergency (not EEA – Level 3)

0800: Emergency escalates to EEA – Level 3 (Max Gen Event Level 5) and MISO directs load-shedding

- Real-Time LMPs/MCPs are administratively set to the default RT Pricing VOLL ($10,000/MWh)

1030: DA Market closes for MP-submitted offers/bids (EEA – Level 3 continues)

- For the next Operating Day (Day 2), Pricing VOLL is set to $5,000/MWh for both DA and RT Markets
- The Pricing VOLL will continue to be used as the RT price cap, and as the RT Administrative Price during EEA – Level 3 conditions
- DA Demand bids into the DA Market will consider the $5,000/MWh Pricing VOLL for the next Operating Day

1200: RT Pricing VOLL drops to $5,000/MWh, due to 4 hours of EEA – Level 3 load-shedding

- Real-Time LMPs/MCPs are administratively set to $5,000/MWh, for the remainder of the day because EEA – Level 3 conditions persist

DAY 2

0000: EEA – Level 3 load-shedding continues; RT Pricing VOLL kept at $5,000/MWh

- Real-Time LMPs/MCPs are administratively set to $5,000/MWh, while EEA – Level 3 continues

0800: EEA – Level 3 load-shedding ends, but Max Gen Emergency continues

- Real-Time LMPs/MCPs are capped by RT Pricing VOLL of $5,000/MWh

1030: DA Market closes for MP-submitted offers/bids, and Max Gen Emergency continues

- For the next Operating Day (Day 3), lower Pricing VOLL to $2,000/MWh for both DA and RT Markets
- Demand bids into the DA Market will consider the lower $2,000/MWh Pricing VOLL for the next Operating Day

2000: MISO terminates Max Gen Emergency

- Real-Time LMPs/MCPs continue to be capped by RT Pricing VOLL of $5,000/MWh

<u>DAY 3</u>

All Hours:

- RT prices will be capped all day by RT Pricing VOLL of $2,000/MWh because the Max Gen Emergency was terminated yesterday after 1030EPT (DA Market close)

1030: DA Market closes

- DA and RT Pricing VOLLs will be $10,000/MWh for the next Operating Day (Day 4)

<u>DAY 4</u>

0000:

- RT Pricing VOLL is reset to $10,000/MWh

The following figure provides a summary of this example:

<table>
<tr><th>Day</th><th>Time (EPT)</th><th>MISO Max Gen Level</th><th>DA VOLL</th><th>RT VOLL</th><th>Use RT VOLL as RT EEA3 Admin Price?</th><th>Use RT VOLL as RT Price Cap?</th></tr>
<tr><td>1</td><td>0:00</td><td>Normal Ops</td><td rowspan="4">$10,000</td><td rowspan="3">$10,000</td><td rowspan="2">No (no declared EEA3)</td><td rowspan="2">Yes</td></tr>
<tr><td>1</td><td>2:00</td><td>Max Gen (not EEA3)</td></tr>
<tr><td>1</td><td>8:00</td><td rowspan="3">Max Gen Event Step 5 (EEA 3)</td><td rowspan="3">Yes (for declared EEA3 area)</td><td rowspan="3">Yes (for non-EEA3 area)</td></tr>
<tr><td>1</td><td>12:00</td><td rowspan="4">$5,000</td></tr>
<tr><td>2</td><td>0:00</td><td rowspan="3">$5,000</td></tr>
<tr><td>2</td><td>8:00</td><td>Max Gen (not EEA3)</td><td rowspan="4">No (no declared EEA3)</td><td rowspan="4">Yes</td></tr>
<tr><td>2</td><td>20:00</td><td>Normal Ops</td></tr>
<tr><td>3</td><td>All Day</td><td>Normal Ops</td><td>$2,000</td><td>$2,000</td></tr>
<tr><td>4</td><td>0:00</td><td>Normal Ops</td><td>$10,000</td><td>$10,000</td></tr>
</table>

Figure 12 – Example of Application of Circuit Breakers

VIII. <u>PROPOSED ORDC UPDATES</u>

Q. HOW DOES MISO PROPOSE TO MODIFY THE RELATIONSHIP BETWEEN VOLL AND THE ORDC?

A. MISO also proposes changing the relationship of the VOLL to the ORDC. MISO agrees with the IMM's recommendation made in the 2023 State of the Market (2016-1) to define the ORDC based on a loss of load probability calculation, scaled to reflect the cost of shedding firm load. MISO proposes a scaling factor of $35,000/MWh, which will be called the System VOLL.

Next, MISO proposes a $6,000/MWh ORDC upper limit to allow prices to appropriately rise towards VOLL as Operating Reserves are depleted. The ORDC should have a large impact during shortage conditions, but there are other components that also impact energy prices, such as generator offers, four other reserve demand curves, congestion, and losses. A $6,000 ORDC cap allows sufficient room for these other pricing components to function ahead of MISO-directed load-shedding, which is administratively priced at $10,000/MWh. In addition, the selection of the $6,000/MWh upper limit recognizes that firm load-shedding may be avoided even when minimal reserves are being cleared. MISO and IMM studies showed that the Loss of Load Probability ("LOLP") curve only reached up to ~60%, as cleared Operating Reserves approached zero. Thus, it is reasonable that the ORDC should not exceed 60% of $10,000/MWh Pricing VOLL, even when cleared reserves are minimal, as MISO-directed load-shedding might not occur.

MISO also proposes a two-step floor for the ORDC ($600 and $1,100), using the same Most Severe Single Contingency ("MSSC") breakpoint as the current ORDC. This is lower than the current $1,100 and $2,100 ORDC steps and will help MISO better manage congestion for small Operating Reserve shortages, while clearing nearly all the available reserve supply. Congestion management is enhanced by the lower ORDC floor, because the market can send better pricing and dispatch signals to resources that are contributing to transmission constraint overloads.

The ORDC floors were also selected to prevent undesirably low prices during declared system emergencies and when Short-Term Reserves ("STR") are scarce. The STR demand curve can reach $500, which is also the value of the Tier 1 Emergency Offer Floor. The $600 step ensures the Operating Reserves price does not fall below these values for small Operating Reserve deficits, when considering the $100 Contingency Reserve Offer Cap. Similarly, the $1,100 step ensures that the Operating Reserve price does not drop below the Tier 2 Emergency Offer Floor (plus the Contingency Reserve Offer Cap).

Q. PLEASE EXPLAIN WHY THE CURRENT ORDC NEEDS TO BE UPDATED.

A. MISO currently has five reserve products to help ensure that reliability of the grid. The original three products were Regulation, Spinning and Supplemental Reserves. In recent years, the Ramp Capability and Short-Term Reserve products were added, as discussed above.

For each reserve product, MISO specifies a target requirement which can vary at different times or conditions. In most intervals, there is sufficient supply to satisfy these reserve requirements, and a Market Clearing Price ("MCP") is established using provided offers and/or lost opportunity costs. When there is insufficient supply to satisfy the reserve requirement, a price is established using a "demand curve." The demand curve should reflect the increased reliability risk for that reserve shortage, while considering the relative (and sometimes cumulative) risks of other reserve shortages.

The ORDC is important as it reflects the combined need of Regulating, Spinning and Supplemental Reserves. These products must be deliverable within 10 minutes (or less for Regulating Reserves) to ensure the grid can withstand the loss of the largest supply source, and thus, an extended deficiency of OR must be avoided. The ORDC has the highest shortage prices, as it is used to escalate prices towards VOLL (the price cap) as cleared Operating Reserves are depleted.

The current ORDC does not fully reflect the reliability conditions of the grid. It is largely defined by two steps ($1,100 and $2,100) and does not increase as the Operating Reserve deficiency worsens, not considering the most extreme deficits thereby not reflecting the increased possibility of MISO-directed load curtailment. The first $1,100 step can also provide challenges for congestion management, even for small Operating Reserve deficits. To address these limitations, MISO is proposing an update to the ORDC, which is depicted in the figure below:

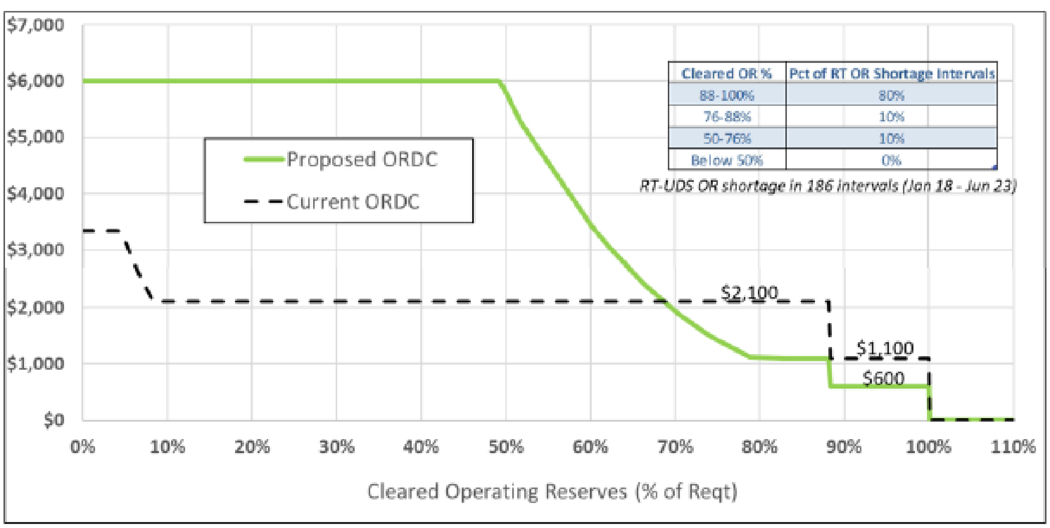


Figure 13 – Comparison of current and proposed ORDC

Q. HOW DO LOSS OF LOAD PROBABILITIES DRIVE THE ORDC SHAPE?

A. As Operating Reserves are reduced, there is an increasing chance for customer demand to exceed supply. It is possible to estimate the cost of a given Operating Reserve shortage, by computing the probability of losing load at that level of Operating Reserves, and then multiplying that by the economic value of the unserved load. In contrast to a relatively flat ORDC defined primarily by a fixed $2,100/MWh step, this approach increases the demand curve as cleared Operating Reserves decrease, while also specifying upper and lower bounds for the demand curve to satisfy other price formation objectives.

This ORDC is constructed by first developing a loss-of-load-probability curve that quantifies the risk of losing load for decreasing amounts of Operating Reserves. MISO's approach compares historical Look Ahead Commitment ("LAC") and Real-Time Security Constrained Economic Dispatch ("SCED") cases to capture Net Load and Gen Outage/Derate uncertainties within a 10 to 30-minute lead time. Then, a Monte Carlo simulation generates the Loss of Load Probability ("LOLP") distribution, for varying Contingency Reserve levels.

Next, the LOLP curve is scaled by the System VOLL of $35,000/MWh, which reflects the financial impact of shedding load across all customer classes (residential, small, and large commercial and industrial). This value is higher than the $10,000/MWh Pricing VOLL used as the price cap and administrative pricing during load-shedding, which prioritizes residential loads, whereas the System VOLL takes into account historical consumption by all the various customer classes.

This higher System VOLL is also consistent with the actions taken by MISO Operations during increasing Operating Reserve deficits, as prolonged deficits below the Most Severe

Single Contingency of ~88% brings firm load-shedding decisions into play. The following figure illustrates how the ORDC shape changes for different values of the System VOLL. Note that the bottom "$10K*LOLP" curve is quite shallow and only reaches ~$1,600/MWh at a 50% Operating Reserve shortage. That pricing is too low given the priorities and actions that would be taken by MISO operations during such shortages. The $35,000/MWh scaling (orange curve), established using the VOLL calculations above, escalates Operating Reserve shortage pricing more appropriately. At the same 50% Operating Reserve shortage, the ORDC now reaches ~$6,000/MWh (illustrated in Figure 13), reflecting the severity of imminent operator actions.

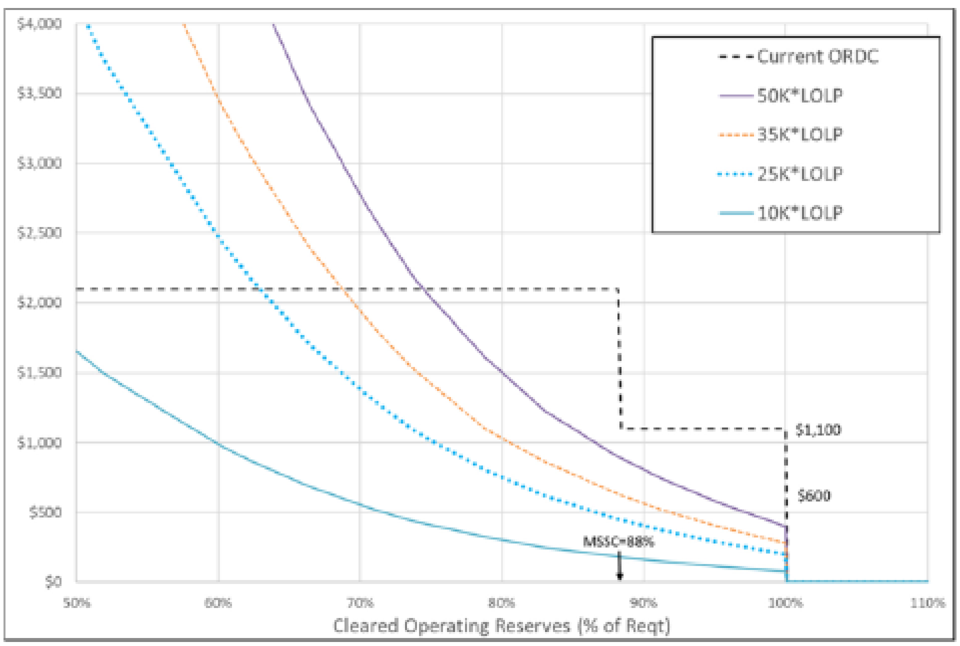


Figure 14 – Impact of System VOLL on ORDC

Q. HOW DOES MISO PROPOSE TO ESTABLISH THE UPPER LIMIT FOR THE ORDC?

A. During extreme Operating Reserve shortages, high energy prices will incentivize beneficial demand response, increased imports, and additional energy production. As the Pricing VOLL is administratively applied during shortage events that lead to MISO-directed capacity emergency load-shedding, prices should rise towards the Pricing VOLL before load-shedding begins and the Pricing VOLL is administratively applied. This upward price movement, prior to administrative application of the Pricing VOLL, is accomplished by ensuring that the ORDC escalates appropriately when deficits become severe, and that the ORDC upper bound is set sufficiently high.

Additionally, the ORDC upper limit should allow sufficient room for other MEC contributions (*i.e*., marginal energy offers and shadow prices from other reserve products) as well as LMP congestion and loss components. The current ORDC is very close to the existing VOLL, whose non-updated low level curtails many otherwise appropriate high LMPs during tight operating conditions.

Accordingly, MISO proposes a $6,000/MWh upper bound for the ORDC. This upper limit ensures that, during severe reserve shortages, the energy prices will approach VOLL to encourage proper response from market participants. This ORDC upper bound also provides a margin of up to $4,000 for other MEC and LMP contributions to the energy prices, before the Pricing VOLL is applied. For example, marginal energy offers can reach $2,000/MWh, and the STR Demand Curve has a $500 upper limit. There are other smaller reserve product demand curves that can also contribute to energy prices.

Q. HOW DOES MISO PROPOSE TO ESTABLISH THE LOWER LIMIT FOR THE ORDC?

A. MISO proposes an ORDC floor of $600/MWh when cleared Operating Reserves are above the MSSC (88%), and $1,100/MWh when cleared OR is below the MSSC, as shown in the following figure:

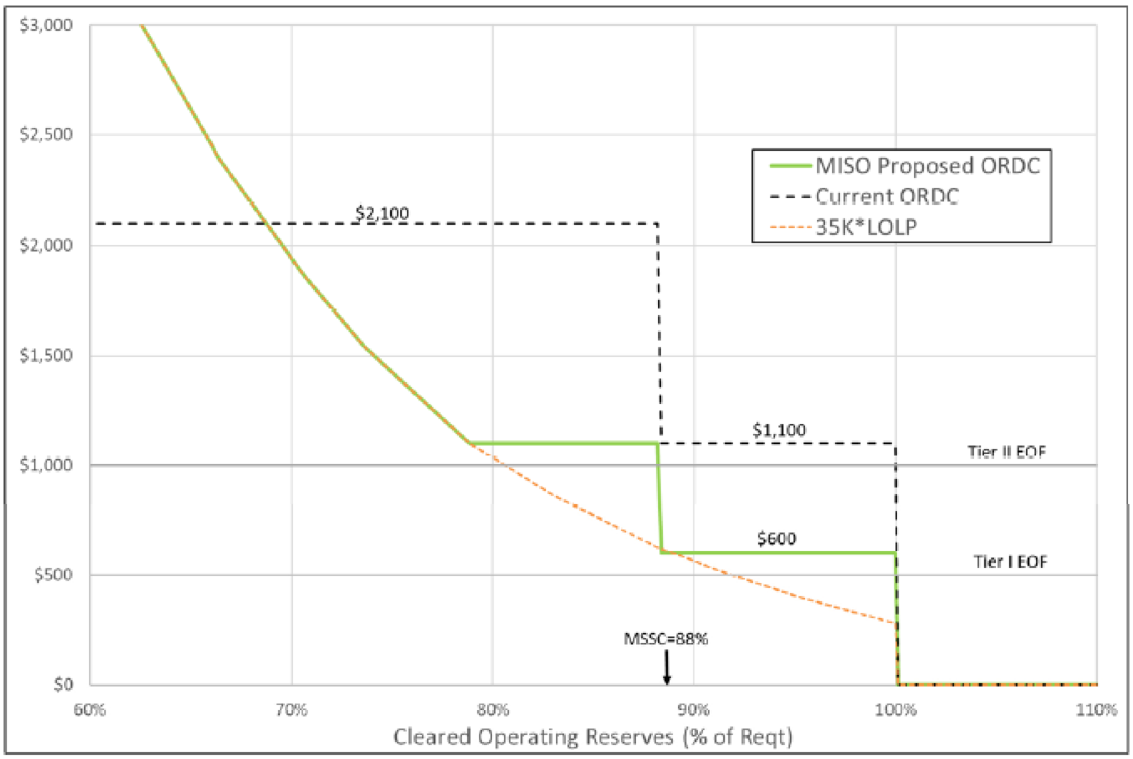


Figure 15 – Depiction of ORDC Floor

Since the launch of the Ancillary Services Market in 2009, the lower bound(s) for the ORDC have been adjusted several times by MISO. Originally, the ORDC had a single $1,100 floor, which ensured that all available Operating Reserves were cleared considering the Energy Offer Cap of $1,000/MWh along with the Contingency Reserve Offer Cap of $100/MWh. It was then determined that the $1,100 floor was too high for certain short-term economic shortages, so a $200/MWh step was added for small deficits (0-4%). With the implementation of FERC Order No. 831, the Energy Hard Offer Cap increased to $2,000/MWh, so an additional $2,100/MWh step was added below the MSSC. More recently, it was determined that the $200/MWh step was no longer needed, due to the introduction of the Ramp Capability Product, and changes to the emergency pricing algorithms.

These changes illustrate the desire of MISO to balance pricing signals with the associated reliability risks. In proposing the ORDC floors in this filing, MISO considered and balanced several competing factors. First, attempting to always clear 100% of available reserve capacity would require a very high ORDC floor of $2,100/MWh. This high floor would lead to inefficient price swings for small Operating Reserve deficits, particularly those lasting only one or two 5-minute intervals. Rather, it is more prudent to set the lower bound(s) high enough to clear the majority of the available Operating Reserves for small Operating Reserve deficits, and to rely on the increasing ORDC to clear additional Operating Reserve capacity for larger Operating Reserve shortages.

Second, the Ramp Capability Product went live on May 1, 2016, and now helps MISO avoid spurious Operating Reserve shortages by better positioning the generation fleet to respond to potential short-term ramping needs. Because there are fewer transient ramping shortages, MISO does not need to create an extremely low ORDC step, such as the previous $200/MWh step.

Third, emergency pricing logic employs Emergency Offer Floors ($500 and $1,000) to prevent energy prices from collapsing when emergency capacity is deployed. The market should avoid going short on Operating Reserves if that would allow prices to fall below one (or both) of these offer floors. This can be accomplished by setting ORDC floors sufficiently high.

Fourth, the STR product, which went live on December 7, 2021, also helps to reduce the potential of Operating Reserve shortages by ensuring that adequate capacity is committed to mitigate potential uncertainties in the upcoming 30-minute to 3-hour timeframe. This product has its own demand curve, which can reach $500/MWh. As the same resource capacity can simultaneously be cleared for Short-Term Reserves and one of the other reserve products (*e.g.*, Reg, Spin, Supp, or Ramp Capability), the current $1,100 step may be too high as the first step given the additional $500 potential impact of a concurrent STR shortage. Thus, when STR is not short, a small Operating Reserve shortage is likely a transient one and will be priced accordingly. But when STR is short, its additional shortage price will complete the pricing signal.

More recently, MISO and the IMM have recognized that the ORDC can impact the effectiveness of congestion management. Operating Reserve shortages impact energy prices through the Marginal Energy Component ("MEC"), which can make congestion management more challenging due to comparatively smaller Marginal Congestion Components ("MCC"). A constrained resource will come unbound once its LMP exceeds its Energy Offer, which is more likely to happen as the MEC increases during an Operating Reserve shortage, and the MCC is insufficient to counter this MEC increase. This can cause transmission constraint violations, which may then trigger Manual Redispatches ("MRDs"), leading to increases in make-whole payments. By reducing the ORDC lower bounds for smaller Operating Reserve shortages, the reduced MEC impact will make congestion management incrementally more effective.

Q. WHY DID MISO SELECT THE $600 ORDC LOWER BOUND?

A. The $600 ORDC lower bound was selected for several reasons. First, when MISO declares a Max Gen Warning or Maximum Generation Event Step 1, the market solution should not violate the Operating Reserve requirement to avoid clearing resources offered at the minimum Tier I Emergency Offer Floor. This is accomplished by setting the floor to be the sum of the minimum Tier I Emergency Offer Floor of $500/MWh and the Contingency Reserve Offer Cap of $100/MWh.

Second, this floor greatly reduces Operating Reserve "economic shortages" compared to an even lower floor (previously $200/MWh).

Third, the proposed floor acknowledges the potential combined pricing impact of Operating Reserve and STR shortages (*i.e.*, the impact of concurrent Operating Reserve and STR shortage could reach the current $1,100 ORDC step).

Fourth, by reducing the first step from $1,100 (current ORDC) to $600, MISO can better manage congestion during small Operating Reserve shortages.

Q. WHY DID MISO SELECT THE $1,100 ORDC LOWER BOUND?

A. The $1,100 ORDC lower bound was selected for several reasons. First, this second step increases the shortage pricing when cleared Operating Reserves fall below the Most Severe Single Contingency, used in EOP-002 Step 4.2.9.4. Second, when MISO declares a Max Generation Event Step 2, the market solution should not violate the Operating Reserve requirement to avoid clearing resources offered at the minimum Tier II Emergency Offer Floor. This is accomplished by setting the floor to be the sum of the minimum Tier II Emergency Offer Floor of $1,100/MWh, and the Contingency Reserve Offer Cap of

$100/MWh. Third, by reducing the second step from $2,100 (current ORDC) to $1,100, MISO can better manage congestion during small Operating Reserve shortages.

Q. HOW WILL THE PROPOSED CHANGES TO THE ORDC HELP MISO BETTER MANAGE CONGESTION IN THE MISO REGION?

A. The ORDC will be lowered for small Operating Reserve shortages, which are the vast majority of shortage intervals (>90%). In these cases, there will be a smaller increase to the Marginal Energy Component of the LMPs, which makes it more likely that the Marginal Congestion Component can continue to effectively manage congestion. The magnitude of the MCC is established using the current set of Transmission Constraint Demand Curves ("TCDCs").

Q. ARE THE EXPECTED IMPACTS OF THE SHORTAGE PRICING PROPOSAL CONSISTENT WITH MISO'S MARKET DESIGN GUIDING PRINCIPLES?

A. Yes. The proposal is expected to produce both short-term and longer-term results that are consistent with MISO's market design guiding principles as summarized below:

- Short-term impacts of the shortage pricing reforms are expected to provide proper financial incentives, and will improve reliability by encouraging appropriate Market Participant actions. If shortage events occur, financial risks will be directed to Market Participants that deviate from their Day-Ahead Market positions and are inflexible to respond to Real-Time Market prices. These expected outcomes are consistent with the guiding principles of supporting an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity; supporting market participants in making efficient operational and investment decisions; and maximizing alignment of market requirements with system reliability requirements.

- In the longer-term, the shortage pricing proposal is expected to inform investment decisions for reliable, flexible resources, which is consistent the guiding principle of supporting market participants in making efficient operational and investment decisions.

IX. PROPOSED EMERGENCY DEMAND RESPONSE ("EDR") OFFER CAP

Q. WHAT IS MISO'S EDR PRODUCT?

A. MISO's EDR product allows MISO to call on EDRs during a NERC Energy Emergency Alert 2 ("EEA - Level 2"), Alert 3 ("EEA – Level 3"), or any other type of emergency event. The EDR product was added in response to capacity shortage events in August 2006 and February 2007 and was vetted before the Demand Resource Working Group and Market Subcommittee. At that time, special rules to prevent price suppression during an emergency were not in effect and FERC encouraged MISO to have additional demand response initiatives similar to other ISOs.

Q. HOW OFTEN DOES MISO DEPLOY EDRS?

A. EDRs have only been deployed once, on September 24, 2014. EDRs make up a very small volume of MISO's available resources, often totaling less than 500 MW with notification times averaging over four hours.

Q. HOW DO EDRS COMPARE WITH LOAD MODIFYING RESOURCES AND DEMAND RESPONSE RESOURCES?

A. EDRs can be assets (*i.e.*, demand reduction) which, in times of need, can help meet the energy balance, but cannot guarantee availability under all levels of Emergency in MISO or be available regularly to reduce demand in the energy markets (like DRRs). In addition, LMR assets that dual register as EDRs can specify the compensation requirements necessary for load reduction (as opposed to resources that register solely as LMRs).

Q. HOW IS THE EDR OFFER CAP DEFINED?

A. The EDR Offer Cap is currently defined to be VOLL in Schedule 30 of the Tariff.

Q. WHAT CONCERNS DOES MISO HAVE WITH THE STATUS OF THE EDR PRODUCT?

A. Given the proposed increase to the Pricing VOLL, MISO has concerns that potential EDR offers capped at a much higher Pricing VOLL would overstate the relative value of EDRs, compared to other types of supply resources.

Q. HOW DID MISO ADDRESS THOSE CONCERNS?

A. MISO held internal and external dialogs to identify potential solutions, as well as the broader considerations for the EDR product. Three potential solutions were discussed with stakeholders.

The first option is to retain the existing EDR infrastructure and set the EDR Offer Cap to a fixed value, such as $3,500/MWh, or the Energy Offer Hard Cap of $2,000/MWh. The second option is to utilize the same offer validation process as for other resources, established by FERC Order No. 831. The third option is to retire and/or replace the EDR instrument.

Q. WHICH OPTION DID MISO CHOOSE FOR EDRS?

A. MISO decided that, in light of the proposed significant increase of the Pricing VOLL, the first option should be adopted in the near term by decoupling the EDR Offer Cap from the Pricing VOLL. MISO proposes that the EDR Offer Cap be set at the fixed amount of $3,500/MWh.

Q. HOW DID STAKEHOLDERS RESPOND TO MISO'S PROPOSAL TO SET THE EDER OFFER CAP AT THE FIXED AMOUNT OF $3,000/MWH?

A. Many stakeholders expressed support for, and none opposed, an EDR Offer Cap pegged at the fixed amount of $3,500. Certain stakeholders expressly stated that they find it reasonable to maintain the current EDR Offer Cap of $3,500/MWh, as the current set of EDR Offers were created with this pricing assumption. Various end use customers also support MISO's proposal to maintain the EDR offer cap at its current level of $3,500 per MWh, in light of the proposal to increase the Pricing VOLL significantly.

X. IMPLEMENTATION AND EFFECTIVE DATE

Q. WHAT SOFTWARE AND SYSTEM UPDATES ARE REQUIRED TO IMPLEMENT THE PROPOSED SHORTAGE PRICING CHANGES?

A. The changes to the VOLL and ORDC can be updated by modifying input parameters of the Market Clearing Engines. It is important to note that these updates will not impact the scope of other work performed as part of MISO's ongoing Market System Enhancements efforts. A process and procedure will be developed to compute the Loss of Load Probability ("LOLP") curve, which is used as part of the ORDC.

Most of the implementation effort will involve the pricing circuit breaker, which will reduce the real-time and/or day-ahead Pricing VOLLs during extended capacity emergencies involving MISO-directed load-shedding. The circuit breaker logic will be automated, to ensure that these VOLL changes are made in an efficient and timely manner. facilitate operator decisions and actions, and minimize the chances of implementation errors occurring during high-risk emergency circumstances. This additional functionality will be implemented in the database, and should not require changes to the Market Clearing Engines. Operator screens will need to be modified/created to allow real-time and day-ahead operations personnel to monitor the operation of the price circuit breaker.

No software and system changes are needed for the proposed EDR Offer Cap, as this value is already fixed at $3,500/MWh.

Removing the caps for the Day-Ahead Price Sensitive Demand Bids and Virtual Demand Bids will require adjustments to Market Portal validation logic.

Q. WHAT UPDATES TO THE BUSINESS PRACTICES MANUALS WILL BE REQUIRED TO IMPLEMENT THE PROPOSED SHORTAGE PRICING CHANGES?

A. BPM-002: Energy and Operating Reserve Markets, will to be revised so that references to VOLL will differentiate between the "Pricing VOLL" and the "System VOLL", and the description of the ORDC curve must be updated to show the use of the System VOLL to scale the Loss of Load Probability Curve.

Q. WHAT EFFECTIVE DATE IS MISO REQUESTING FOR THE PROPOSED TARIFF REVISIONS?

A. MISO is requesting an effective date of Operating Day September 30, 2025, for the proposed Tariff revisions. This implementation date is feasible because the associated system and software changes will not impact the scope of MISO's other Market System Enhancement efforts.

MISO is filing the Tariff changes early enough to allow time for the necessary resources to be budgeted and allocated, and for the required software, system and procedural changes to be developed and put in place, on time for the implementation of the proposed shortage pricing rules. For this purpose, MISO is requesting the Commission to issue an order on this filing by April 1, 2025, so MISO has sufficient time to devote the resources and efforts needed to implement the proposed Tariff changes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Affidavit of Zakaria Joundi

COUNTY OF HAMILTON)
)
STATE OF INDIANA)

Zakaria Joundi, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Zakaria Joundi, and the statements contained therein are true and correct to the best of his knowledge and belief.

Zakaria Joundi

SUBSCRIBED AND SWORN BEFORE ME, this 12 day of November, 2024.

Rhiannon Rena Shelley
(*Notary Public Signature*)

RHIANNON RENA SHELLEY
Clinton County
My Commission Expires
September 27, 2025

Commissioned in Clinton county.

Commission Number: 705772

Commission Expires: 9/27/2025

Tab E

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)** **)**	**Docket No. ER25-___-000**

Affidavit of David B. Patton, Ph.D.

I. Qualifications and Purpose

1. My name is David B. Patton. I am an economist and the President of Potomac Economics Ltd. Our offices are located at 10560 Arrowhead Drive, Fairfax, VA 22030. Potomac Economics is a firm specializing in expert economic analysis and monitoring of wholesale electricity markets. Potomac Economics has served as the Independent Market Monitor ("IMM") for the Midcontinent Independent System Operator, Inc. ("MISO") since 2002. Potomac Economics serves in a substantially similar role for the New York Independent System Operator, Inc., ISO New England, Inc., and the Electric Reliability Council of Texas.

2. As the Market Monitor for MISO, Potomac Economics is responsible for assessing the competitive performance of the MISO markets, including identifying and remedying market design flaws and abuses of market power. This work has included preparing reports that assess the performance of these markets and providing advice on numerous issues related to market design and economic efficiency.

3. I have worked as an energy economist for more than 30 years, focusing primarily on the electric utility and natural gas industries. I have provided strategic advice, analysis, and expert testimony in the areas of electric power industry restructuring, pricing, mergers, and market power. I have also advised Regional Transmission Organizations on transmission pricing, market design, and congestion management issues. I have provided expert testimony and analysis of market power issues and competition in a number of mergers and market-based pricing cases before the Federal Energy Regulatory Commission ("the Commission"), state regulatory commissions, and the U.S. Department of Justice.

4. Prior to my experience as a consultant, I served as a Senior Economist in the Office of Economic Policy at the Commission, advocating a variety of policy issues including transmission pricing and open-access policies, market design issues, and electric utility mergers. As a member of the Commission's advisory staff, I worked on policies reflected in Order No. 888, particularly on issues related to power pool restructuring, independent system operators ("ISOs"), and functional unbundling. I also analyzed alternative transmission pricing and electricity auctions proposed by ISOs.

5. Before joining the Commission, I worked as an economist for the U.S. Department of Energy. During this time, I helped to develop and analyze policies related to investment in oil and gas exploration, electric utility demand-side management, residential and commercial energy efficiency, and the deployment of new energy technologies. I have a Ph.D. in Economics and an M.A. in Economics from George Mason University, and a B.A. in Economics with a minor in Mathematics from New Mexico State University.

6. The purpose of this affidavit is to support certain proposed revisions to MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"). In particular, MISO proposes changes to its Operating Reserve Demand Curve (ORDC), and to its Value of Lost Load (VOLL). These changes aim to increase the efficiency of energy and ancillary service prices and to reform the market price cap and its application during load shedding events.

7. The reform of the ORDC will help align energy and ancillary service pricing during shortages with the underlying value of reserves, thereby resulting in more efficient prices and incentives. This will lead to improved scheduling and dispatch, availability of supply during tight conditions, and long-term investment and retirement decisions. These changes

involve an updated system-wide Value of Lost Load (System VOLL) and a revised ORDC slope to better reflect the marginal value of operating reserves on reliability. We have recommended these changes in our annual State of the Market reports since 2016, and we support them.

8. MISO is changing the energy and ancillary services market price cap by defining a "Pricing VOLL." This is an alternative measure of VOLL calculated specifically to apply to market price caps and for pricing during load shedding events. MISO is also proposing shortage pricing circuit breakers that modifies the Pricing VOLL when shortages extend beyond certain time durations. This is logical because the empirical evidence supports a Pricing VOLL that tends to decrease as consumers have more time to adjust to an outage.

9. We also support the removal of caps on day-ahead price-sensitive load and virtual demand bids. This is important because such day-ahead bids must encompass expected higher real-time shortage pricing that would be possible under MISO's proposed changes. Before FERC Order No. 831, MISO did not have any caps on day-ahead price-sensitive load and virtual demand, and we agree with MISO that it is appropriate not to impose these bidding restrictions. The MISO Tariff will continue to maintain the alignment of supply offer caps with FERC Order No. 831 requirements.

II. ORDC Reform

10. The Operating Reserve Demand Curve increases prices for reserves and energy during times when operating reserves are short – i.e., available resources are not sufficient to

satisfy the demand for energy while holding the entire complement of reserve products.[1] MISO is proposing revisions to the ORDC that will improve energy and ancillary services pricing under shortage conditions. We have been a proponent of reforming the ORDC since at least 2016 to improve shortage pricing.

11. The central feature of efficient shortage pricing is that it reflects the value of foregone reserves. When a market is short of reserves, market prices for reserves and higher-valued products like energy should signal the marginal reliability impact of not holding the full complement of reserves. Efficient shortage prices play a key role in motivating good resource availability and performance, facilitating efficient interchange, encouraging demand response, and establishing economic signals to guide investment and retirement decisions in the long run. Efficient prices also compensate for resource flexibility, which is becoming increasingly important as intermittent resource growth (wind and solar) raises the volatility of supply.

12. As we have explained in our *State of the Market* reports, MISO's current ORDC does not accurately reflect the reliability value of reserves. It overstates the reliability risks for small, transient shortages and understates them for deep shortages. Additionally, the highest prices under the current ORDC are $3,500 per MWh, which has adverse interactions with PJM's pay-for-performance rules. This is because PJM's rules price modest shortages as high as $6,000 per MWh, which will lead to inefficient imports and exports when both markets are tight. The ORDC is defined by the value of reserves to the system at various levels, which should be given by:

1 The ORDC directly sets the price for supplemental reserves, but it is only one component of prices for spinning reserves, regulation, and energy prices.

Value of Reserves = value of lost load (System VOLL) * Loss of Load Probability

13. The System VOLL reflects the costs experienced by all customer classes from an interruption of service (loss of load). The *probability of losing load* (which MISO now calls the Loss of Load Probability Curve) is an estimate of the probability of losing load at any given reserve level. Hence, at any given reserve level, the equation gives the expected cost of an outage and, so, the marginal value of avoiding it. MISO proposes reforms to both components of this equation.

14. As we discuss below, System VOLL is essentially a static value in the formula above. The Loss of Load Probability Curve changes with reserve levels -- as reserves increase, the probability of losing load decreases. Given these values, a downward sloping relationship can be graphed that intersects the y-axis at a value converging to System VOLL and approaches the x axis asymptotically as reserves become large.

15. MISO's current ORDC does not accurately reflect the marginal reliability value of shortages for two reasons. First, the System VOLL MISO currently uses is understated at $3,500 per MWh. It is based on an outdated study and is heavily weighted toward interruption costs of residential customers. Accordingly, MISO is changing this, and we support MISO's proposed changes. Second, the current ORDC does not properly reflect probability of losing load. This is mainly because the slope of the current ORDC does not reflect the probabilities of multiple contingencies and uncertainties occurring simultaneously. MISO proposes a new slope based on a much more accurate Loss of Load Probability Curve.

16. In our past *State of the Market* reports, we have concluded that an efficient ORDC should: a) reflect the marginal reliability value of reserves at each shortage level; b) consider all supply contingencies and uncertainties; and c) have no artificial discontinuities that can lead to excessively volatile outcomes. We have reviewed MISO's proposal and find that the reforms achieve these goals and improve other aspects of shortage pricing.

A. System VOLL

17. MISO defines a System VOLL as the "value that represents the price consumers are willing to pay to avoid an interruption of electrical service" across all service classes (residential, commercial, industrial). It is the cost incurred by customers when an outage occurs. Therefore, when the MISO system is unable to meet system requirements and load is interrupted, customers incur a cost equal to System VOLL. Estimating a VOLL presents a number of challenges, including variation across customer classes and during the time of day and season, among other things. The current VOLL used by MISO is $3,500 per MWh. This value was established in 2007 based mainly on an estimate of residential customers' interruption costs. MISO has agreed this value is no longer an appropriate VOLL.

18. Since 2020, we have estimated and updated a VOLL based on a model developed by Lawrence Berkeley National Laboratory. This is a well-known model and is cited and used by many practitioners. Using the Berkeley Model and recent MISO customer class data, we estimated a VOLL of close to $33,000 per MWh.[2] MISO used a similar approach, employing the same Berkeley model with minor differences in applying it and arrived at

2 The econometric model in the Berkeley studies estimates the effects on outage cost from key parameters specific to the affected customers. Mainly, the model specifies the impact on outage costs based on outage duration, customer class, annual consumption, time of day and season, and other qualitative factors.

$35,000 per MWh. We agree with MISO using this value as the System VOLL for scaling the ORDC.

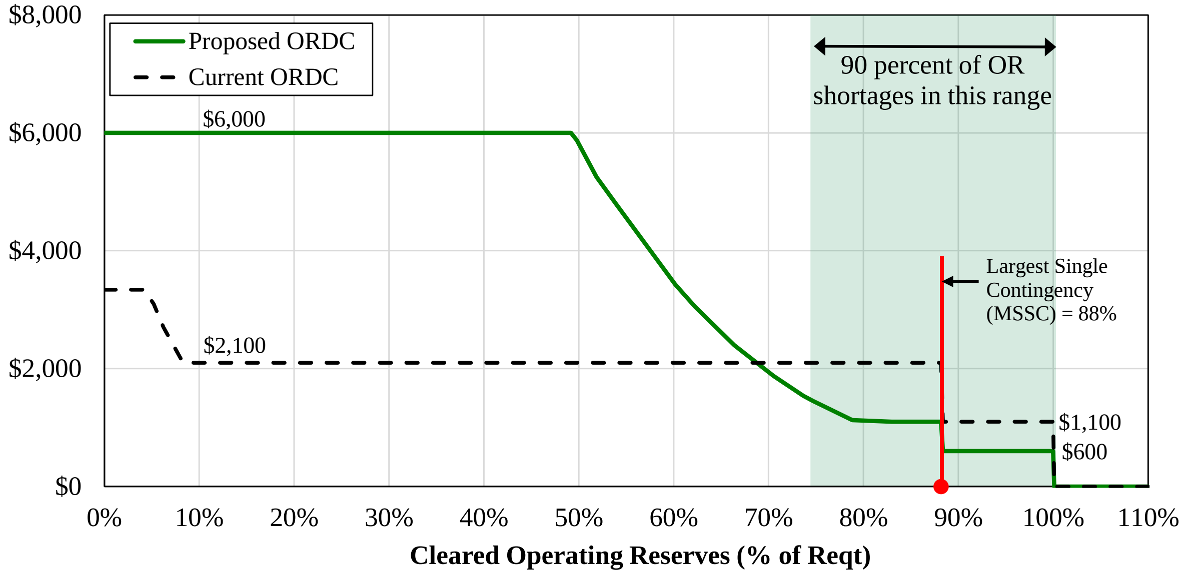
B. Improving the Slope of the ORDC

19. The slope of the ORDC is determined by how the Loss of Load Probability Curve changes as the level of operating reserves changes. The probability of losing load depends on vast combinations of random contingencies and other factors (wind forecast and load forecast errors, and NSI uncertainty) that could occur when MISO is short of reserves. We estimated this probability using a Monte Carlo model that simulates these factors. Our simulated loss of load function showed a flatter slope than the sloped portion of MISO's current ORDC. Moreover, during severe reserve shortages, an ORDC based on our loss of load estimates and an appropriate VOLL showed MISO's current ORDC substantially understated the value of reserves. MISO is proposing a new ORDC that more closely reflects the true probability of losing load.

C. The Revised ORDC

20. MISO has agreed with our approach to the ORDC and proposed an ORDC that both accepts a higher VOLL and uses a slope reflecting realistic loss of load probabilities. The new proposed ORDC is shown in Figure 1.

Figure 1: MISO's Proposed Operating Reserve Demand Curve



21. Under MISO's proposed ORDC, when the available reserves are more than 100 percent, the ORDC price is zero, which is reasonable. When reserves are not sufficient to cover the largest single contingency, the reserve price is $600 per MWh, less than the current $1,100 per MWh. The initial $600 step ensures that Operating Reserve shortage prices do not fall below the sum of (1) the Tier I Emergency Offer Floor* of $500 per MWh (which is also the max Short-Term Reserve (STR) Demand Curve) and (2) the Contingency Reserve Offer Cap of $100 per MWh. This second step sets prices when cleared reserves fall below the largest single contingency. The next step value in the curve is $1,100 per MWh and is the sum of (1) the Tier II Emergency Offer Floor* of $1,000 per MWh (also the Energy Offer Soft Cap), and (2) the Contingency Reserve Offer Cap of $100 per MWh. This floor prevails until shortages reach about 78 percent, at which point the calculated value of reserves (VOLL*LOLP Curve) is employed for pricing up to about a 50 percent reserve level.

22. At around a 50 percent reserve shortage and less, the proposed ORDC flattens at $6,000 per MWh. This plateau is justified for at least three reasons: (i) very few shortages would be priced in this range as the figure shows; (ii) pricing shortages much higher could result in inefficient interchange because most of MISO's neighbors price shortages at lower prices; and (iii) higher levels could cause MISO's dispatch model to make inefficient trade-offs between retaining reserves and managing constraints.

23. In summary, an improved ORDC that better aligns shortage pricing with the marginal reliability value of the foregone reserves will result in more efficient economic signals that govern both short-term and long-term decisions by MISO's participants.

III. Pricing VOLL

A. Definition and Rationale

24. MISO is proposing to define a Pricing VOLL that like the System VOLL is a weighted average price of customer interruption costs. However, the weights are different than for the System VOLL. The weights of the Pricing VOLL are based on the interruption costs faced by consumers with the lowest willingness to pay for them. The Pricing VOLL is established using the same Berkeley model, just like the System VOLL, but the Pricing VOLL weights customer classes differently. The System VOLL weights residential, small commercial/industrial, and large commercial/industrial customer classes nearly equally, in accordance with annual MWh of consumption. In the event of a pervasive system outage, all customer classes would be affected. The Pricing VOLL weights residential customers at 85 percent, under the theory that some balancing authorities may be able to concentrate the curtailments disproportionately on residential load.

25. Based on these weightings, the Pricing VOLL is set at $10,000 per MWh and replaces the $3,500 per MWh VOLL in the Tariff. The new Pricing VOLL fits efficiently with the updated System VOLL used in the ORDC. The Pricing VOLL will allow efficiently high prices when the system is deeply short, which may include the maximum price set by the ORDC plus high congestion and loss components.

B. Market Price Circuit Breaker

26. MISO is proposing a "Market Price Circuit Breaker" that would reduce temporarily the Pricing VOLL during persistent EEA-3 capacity shortage events. A real-time load shedding event occurs under EEA-3 (Max Gen Emergency) declarations. MISO proposes to reduce the application of the Pricing VOLL in real-time from $10,000 per MWh to $5,000 per MWh when the EEA3 extends beyond four hours. If the EEA3 extends to the gate closure of the day-ahead market (10:30 a.m. EPT), then both the day-ahead and real-time Pricing VOLL is reduced to $5,000 per MWh for the following operating day. Finally, the Pricing VOLL is reduced to $2,000 per MWh if the EEA3 extends to additional day-ahead gate closures.

27. We support the Market Price Circuit Breaker because load interruption costs per MWh decline as an interruption is extended. This is due to: a) the ability of customers to undertake mitigating actions; and b) the fact that some of the interruption costs are one-time costs that occur at the beginning of the event. MISO has supported this by illustrating the decline in residential outage costs using the Berkeley model.

28. Finally, extremely high costs over extended shortage periods that exceed the true shortage costs can generate adverse long-term effects. These effects were apparent during Winter Storm Uri when multi-day load shedding led to widespread defaults and bankruptcies.

IV. Remove Offer Caps for DA Price Sensitive Bids and Virtual Demand

29. With the recommended increase in Pricing VOLL, MISO also recommends removing the Energy Offer Hard Price Cap for Price Sensitive Demand Bids and Virtual Demand Bids for the Day-Ahead Market. These are currently set at $2,000 per MWh, so it is logical to allow bids up to the newly created Pricing VOLL. This is important because both types of bidders must be permitted to reflect their expectations of real-time prices in their day-ahead bids. Because real-time prices may rise to $10,000/MWh, setting bid caps lower than this level could encumber legitimate day-ahead bids in periods when the probability of real-time shortages is very high. Therefore, we support removing the bid caps, which will implicitly cause them to be capped at the Pricing VOLL of $10,000 per MWh. Supply offer caps, as required by FERC Order No. 831, will remain in place.

V. Conclusion

30. Since 2016 we have recommended improvements to shortage pricing through a revised ORDC. MISO has proposed reforms that satisfy these concerns, and we support the changes. We also support the creation of Pricing VOLL to establish price caps and to manage pricing during EEA3 emergencies.

31. These improvements will be increasingly necessary as MISO transitions to much heavier reliance on intermittent resources. The uncertainties associated with these resources will likely lead to increasingly frequent transitory shortages. Pricing these shortages more efficiently will generate efficient revenues and incentives for dispatchable resources that complement the intermittent resources and will be essential for maintaining reliability.

32. This concludes my affidavit.

ATTESTATION

I am the witness identified in the foregoing Affidavit of David B. Patton, Ph.D. I have read the affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

David B. Patton, Ph.D.

Subscribed and sworn before me this 7th day of November 2024

Notary Public

My commission expires: 11/30/25

MATTHEW JAMES CARRIER
NOTARY PUBLIC
REG. #7233763
COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES NOVEMBER 30, 2025