January 28, 2022

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

Re:  Southwest Power Pool, Inc., Docket No. ER22-____-000  
Submission of Tariff Revisions to Add Uncertainty Reserve Product to the Integrated Marketplace

Dear Secretary Bose:


SPP is requesting that the Commission issue an order in this docket as soon as practicable, but not later than April 28, 2022 which is approximately 90 days after submission of this filing. SPP requests an effective date of “12/31/9998”\(^2\) for the Tariff Records submitted in this filing in order to allow SPP staff to develop, test, and move the proposed revisions into the production phase of SPP’s software systems. SPP will submit a filing with the Commission specifying a precise effective date prior to implementation. SPP will work as quickly as practicable to technologically implement the Tariff revisions proposed herein. As of the date of this filing, implementation is targeted for the fourth quarter of 2022.

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1. Southwest Power Pool, Inc., Open Access Transmission Tariff, Sixth Revised Volume No. 1. References in this filing to "Tariff" refer to the version of SPP’s Tariff currently in effect. "Proposed Tariff" refers to a version reflecting the revisions proposed in this filing. All capitalized terms not otherwise defined in this filing shall have the definitions assigned by the Tariff.

2. See, e.g., Implementation Guide for Electronic Filing of Parts 35, 154, 284, 300, and 341 Tariff Filings at 10 (Nov. 14, 2016) ("If the effective date is not known at the time of the filing, such as the effective date is contingent on FERC approval . . . the date of 12/31/9998 must be used.").
SPP respectfully requests waiver of the Commission’s timing requirements to allow these tariff revisions to be effective more than 120 days after the date of filing.

I. BACKGROUND

A. SPP

SPP is a Commission-approved Regional Transmission Organization ("RTO"). It is an Arkansas non-profit corporation with its principal place of business in Little Rock, Arkansas. SPP currently has 109 members, including 16 investor-owned utilities, 14 municipal systems, 20 generation and transmission cooperatives, 8 state agencies, 17 independent power producers, 13 power marketers, 14 independent transmission companies, 1 federal agency, 4 large retail customers, and 2 alternative power/public interest entities. As an RTO, SPP: (1) administers, across the facilities of SPP’s Transmission Owners, open access transmission service over approximately 70,000 miles of transmission lines covering portions of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming; and (2) administers the Integrated Marketplace, a centralized day-ahead and real-time Energy and Operating Reserve market with locational marginal pricing and market-based congestion management.

B. Stakeholder Approval

In light of the many challenges and opportunities facing the SPP Region, in March 2018, the SPP Board of Directors (“Board”) and Members Committee created the Holistic Integrated Tariff Team (“HITT”) to comprehensively review SPP’s tariff policies. The SPP Board appointed 15 stakeholders to the HITT, including Board members, state regulators, and representatives of diverse sectors within SPP’s membership. The HITT’s purpose was to make high-level policy recommendations needed to assure continued reliable and cost-effective delivery of electricity to end-use customers.

The HITT conducted 17 meetings between April 2018 and June 2019, during which it held educational sessions, reviewed numerous requests for information, and heard stakeholder presentations before drafting comprehensive recommendations. During the early HITT meetings, the HITT developed the following specific goals based on its mandate from the SPP Board:

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• Develop a high-level policy recommendation as to how SPP can align its transmission planning processes and resource adequacy needs with SPP’s Integrated Marketplace and Tariff requirements. (Issue 1A)
• Review existing transmission cost allocation methodologies in light of Integrated Marketplace implementation and significant changes in generating resources. Upon completing the review, and in consideration of recommendations from the HITT for Issue 1A, the team will develop any needed high-level cost allocation policy recommendations for consideration by the Regional State Committee (“RSC”) and/or Cost Allocation Working Group (“CAWG”). (Issue 1B)
• Develop a holistic understanding of SPP’s Integrated Marketplace and the essential services needed for the region in light of significant changes in generating resources and developing technology. Additionally, develop a better understanding of market products in other regions/markets. Upon obtaining this understanding, develop high-level policy recommendations as to how to enhance SPP’s Integrated Marketplace and Tariff requirements. (Issue 2)
• Review potential load growth opportunities for the SPP Region and make recommendations as to how SPP can assist member companies in realizing load growth. After completing the review, the HITT will develop high-level policy recommendations as to how SPP can enhance or change existing processes, including Attachment AQ studies, to help facilitate load growth opportunities in the SPP Region. (Issue 3).

Using these goals as a guide, the team considered a wide range of potential recommendations using an interdependencies matrix depicting how each recommendation is interrelated with SPP’s functions and processes. The HITT coordinated its efforts to gain synergies and support from, rather than interfering with, the activities of other SPP working groups.

In July 2019, at the conclusion of more than a year’s work, the HITT presented 21 high-level recommendations in four categories for the SPP Board’s consideration. The HITT Report detailing the recommendations is a product of collaboration and negotiation and is a result of the SPP stakeholder process. All recommendations had majority support among SPP’s stakeholders serving on the HITT and many had broad

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6 The four categories are: reliability, marketplace enhancements, transmission planning and cost allocation, and strategic.
support. The SPP Board approved the HITT report and recommendations on July 30, 2019.\(^7\)

Among the recommendations that came out of the HITT process is the proposal in this instant reliability filing to develop an uncertainty product that allows for addressing the potential reliability issues associated with an increased reliance on forecastable generation.\(^8\) The Market Working Group ("MWG") considered this HITT recommendation and developed a white paper on the topic during the course of its monthly meetings following SPP Board approval of the HITT Report.

The recommendations from the white paper were subsequently used to develop the proposed revisions to the Tariff. These proposed Tariff revisions were reviewed and approved through the SPP stakeholder process, including a meeting of the MWG on April 20, 2021;\(^9\) a meeting of the Operating Reliability Working Group ("ORWG") on June 3, 2021;\(^10\) a meeting of the Regional Tariff Working Group ("RTWG") on June 17, 2021;\(^11\) a meeting of the Markets and Operations Policy Committee ("MOPC") on

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\(^7\) See Board of Directors/Members Committee Meeting Minutes No. 185, dated July 30, 2019, at Agenda Item 5 posted at: https://spp.org/documents/60364/bod-mc%20minutes%20&%20attachments%2020190730.pdf.

\(^8\) HITTT Report at 3, Reliability Recommendations, Item 4.

\(^9\) See MWG Minutes, dated April 20-21, 2021, at Agenda Item 8 posted at: https://www.spp.org/documents/64566/mwg%20minutes%20&%20attachments%2020210420-21.pdf. The MWG develops and oversees policies and procedures related to the Integrated Marketplace protocols that define SPP’s wholesale markets, including energy and operating reserve, congestion management, congestion hedging, demand response and market power mitigation. The MWG proposes changes to the SPP Tariff and other governing documents to implement suggested market changes.

\(^10\) See OWRG Minutes, dated June 3, 2021, at Agenda Item 7 posted at: https://www.spp.org/documents/64820/orwg%20minutes%2020210603.pdf. The ORWG develops and oversees policies and procedures related to the reliable and secure operation of the Bulk Electric System within SPP’s Reliability Coordinator, Balancing Authority and Reserve Sharing Group footprints. The ORWG ensures these operating policies are consistent with North American Electric Reliability Corporation and regional reliability standards.

July 12-13, 2021. The SPP Board approved the proposed revisions at its meeting on July 27, 2021. While SPP recognizes that stakeholder approval does not by itself cause a filing to be just and reasonable, SPP requests that the Commission extend appropriate deference to the wishes of SPP’s stakeholders, consistent with Commission precedent.

\[10617.pdf\]. The RTWG develops, implements and oversees SPP’s Open Access Transmission Tariff. The RTWG provides input on regulatory or implementation issues not specifically covered by the tariff and issues where there may be conflicting or differing interpretations of the Tariff.

\[12\]
\[10617.pdf\]. The RTWG develops, implements and oversees SPP’s Open Access Transmission Tariff. The RTWG provides input on regulatory or implementation issues not specifically covered by the tariff and issues where there may be conflicting or differing interpretations of the Tariff.

\[13\]
See MOPC Meeting Minutes, dated July 12-13, 2021, at Agenda Item 6 posted at:
https://www.spp.org/documents/65011/2107%20july%20mopc%20minutes.pdf. The MOPC consists of a representative officer or employee from each SPP Member and reports to the SPP Board. Its responsibilities include recommending modifications to the SPP Tariff. See Southwest Power Pool, Inc., Bylaws, First Revised Volume No. 4 at Section 6.1.

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II. PURPOSE AND JUSTIFICATION FOR PROPOSED TARIFF REVISIONS

The continuing penetration of renewable-powered energy Resources has resulted in a need for flexible capacity availability during times of deviation from forecasts. The Ramp Capability product proposed by SPP in Docket No. ER20-1617\(^{15}\) served as the initial step in procuring the needed flexibility through a short time horizon, market-based product. This filing will expand the availability of flexible capacity via a longer time horizon, market-based product.

The inverter-based generation expansion in SPP began with only a few hundred megawatts (“MW”) of installed wind capacity in 2007, grew to 8.5 gigawatts (“GW”) of installed capacity in 2014, and now inverter-based, nearly entirely renewable-powered, generation represents 31 GWs of SPP’s installed capacity. Renewable-powered generation represents over 30% of SPP’s total generation, and the SPP Region has experienced sustained penetrations (amount of renewable-powered generation serving load) of greater than 87% with a peak wind-powered penetration of 84% in May 2021.\(^{16}\)

SPP’s generator interconnection queue (“GI Queue”) is approximately 95% renewable-powered energy, strongly suggesting that the recent sharp trend upwards in renewable capacity must be expected to continue. While the continued transition to renewable-powered generation by SPP’s stakeholders has resulted in load being served with more carbon neutral, low cost energy, this transition has introduced a significant increase in the variability that must be managed in SPP market and reliability operations.

Unlike traditional thermal Resources, which generally have a reliable and consistent source of fuel, renewable-powered energy Resources rely on naturally occurring, variable fuel sources which must be forecasted in order to determine the forward capabilities of the Resources for both market and reliability operations. Although sophisticated and reasonably accurate, these forecasts can, and often do, deviate from realized generation significantly over a short period of time. These deviations require SPP to have sufficient flexible capacity available when variable

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\(^{16}\) The records for total renewable and wind penetration (with respect to load) were both set on May 8, 2021 where total renewable penetration was 87.5% and wind was 84%. 
generation underperforms. These variations in the total system supply requirements stress the SPP generating fleet as it is forced to ramp up in order to replace the increasing amount of unrealized expected generation.

While renewable energy Resource forecasting continues to improve, SPP remains at the mercy of the weather, and, at times, the generation forecast varies significantly from the actual output. The uncertainty increases in relation to the forecast horizon such that there can be significant difference just a few hours from real-time. In addition to the flexibility needs associated with renewable Resource variability, flexibility needs persist due to traditional operational drivers such as forecasted or unforeseen changes in the load, net scheduled interchange (“NSI”), and Resource availability. These combined drivers necessitate increased flexibility and require SPP to be conservative from a committed capacity perspective. As the amount of renewable-powered generation increases in the SPP footprint, and absent a market-based mechanism to ensure reliable operations given the increased uncertainty, an increase in out-of-market-actions has become necessary in order to ensure the grid could withstand the potential for large swings in actual output or the renewable forecast. These out-of-market-actions, while undertaken to ensure reliability, are opaque from the participants’ perspective. This opacity can result in pricing distortions due to the excess supply on the grid and the lack of a pricing mechanism associated with the reliability service, i.e., flexibility, being provided.

SPP currently manages flexibility needs on multiple horizons. Prior to the Day-Ahead Market (generally 1 to 7 days in the future), SPP manages flexibility needs via daily studies and operator-recommended longer-term actions, such as extending the commitment periods of online Resources that are scheduled to go offline or committing additional generation (some of which may need several days’ notice in order to be available). Flexibility needs that arise after the Day-Ahead Market has run, but before the Real-Time Balancing Market (“RTBM”) runs, are managed via commitments from various Reliability Unit Commitment (“RUC”) studies and operator initiated commitments (out of market). Soon, SPP will manage the flexibility needs near Real-Time with the Ramp Capability product, which is currently scheduled for implementation in the first quarter of 2022.

Historically, energy dispatch tends to use the maximum ramping capability of low-cost Resources resulting in flexibility needs being met through residual amounts. This residual flexibility is not currently valued in the market. With changes in both the residual flexibility of online generation and increases in system variability over time periods greater than an hour prior to real-time, operators have experienced challenges in maintaining the levels of flexibility needed to maintain reliability when the

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17 Generation can under or over perform relative to forecast. Uncertainty Reserve product addresses underperformance.
probability is high that large variations may occur. Because the balance between residual flexibility and system variability is expected to tighten in the future, efficient methods to assist in providing the needed flexibility are increasingly important to economic and reliable operations.

SPP has experienced events where low system flexibility resulted in increased risk to reliability. Low flexibility can occur due to numerous factors such as load, wind, and Resource forecast errors. Additionally, changes in fuel pricing dynamics, such as low natural gas prices, can result in many of SPP’s short-lead time Resources being committed by the Day-Ahead Market to serve energy, leaving scant online and offline capacity to respond to changes in system conditions in the required timeframe. As these issues arise today, they must be addressed through out-of-market operator actions via either the RUC process or manual commitments. With the large amounts of renewable-powered generation in the GI Queue, observed issues with uncertainty in forecasts will continue to grow in magnitude and frequency.

To explore this growing need, SPP conducted an Uncertainty Product Study (“Study”)18. The Study investigated new market functionality in the form of a product to procure and price the system flexibility necessary to address both forecasted and unforeseen (uncertainty) changes in system needs. SPP conducted this analysis via simulations of historical production market cases that presented the operational challenges SPP and its membership believe will become more common as the generation make-up in the SPP Region continues to evolve towards a higher percentage of renewable-powered generation. The primary deliverable of the Study was to compare the proposed new market functionality to the current out-of-market actions used to address it, identifying a more economic, transparent, and systematic solution to the ever growing variability and resulting flexibility needs.

The simulations in the Study show that factoring the historically observed uncertainty into the market process with statistical methods, in the form of a flexibility requirement, should reduce out-of-market actions, managing flexibility needs while increasing transparency by reflecting system needs in the prices and reducing make whole payments (“MWP”).19

18 The results of the Study are included in the white paper. The white paper is posted at: https://www.spp.org/spp-documents-filings/?id=21069 (see zip file named “RR449 - Uncertainty Product” and file named “HITTR4_Uncertainty Product_Whitepaper.pdf).

19 To evaluate the changes in operational costs resulting from procuring flexibility via the proposed market product rather than relying on the historical out-of-market operator actions SPP compared a variety of economic and reliability factors such as:
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The proposed revisions establish a process to determine the amount of flexibility required for reliable market operations as well as to procure and price that flexibility consistent with least-cost principles using a new market product, the Uncertainty Reserve product. SPP expects that the Uncertainty Reserve product will:

a. Increase the reliability of market operations by factoring statistical uncertainty impacts into both commitment and dispatch;  
b. Reduce MWPs and the impacts of price suppression resulting from out-of-market actions taken to maintain the reliability of the bulk electric system; and  
c. Provide transparent prices and a new revenue stream for online and offline resources that can participate.

A. Uncertainty Reserve Will Increase Reliability by Factoring Statistical Uncertainty Impacts into Both Commitment and Dispatch

As demonstrated in the Study, the existing market mechanisms do not have a way of determining or procuring flexibility, relying on out-of-market operator actions to mitigate the flexibility needs in excess of the residual flexibility on the Resources providing Energy and Operating Reserves in the market. Routinely, SPP has observed examples where, due the nature of least-cost optimization, the market solves economically in order to reliably meet the system needs modeled in the defined market products, while leaving little to no residual flexibility available to respond to system needs not explicitly procured with a defined market product.

- Out-of-market manual commitments vs commitments as a result of the market mechanism  
- Changes in SPP’s cost and capability to reliably manage flexibility  
- Total cost to produce

Although SPP’s Uncertainty Reserve product design was created for different reasons than the Midcontinent Independent System Operator, Inc.’s (“MISO”) Short-Term Reserve (“STR”) Product, it is our understanding that the SPP Uncertainty Reserve product is similar to the STR Product in four ways:

1) It is a forward product operating on a longer time horizon than regulation and contingency reserves; 2) It allows both online and offline resources to participate; 3) Offers are used for only offline resources, while only lost opportunity is used for online; and 4) The product exists in both the day-ahead and real-time markets. MISO’s STR Product was approved by the Commission on January 31, 2020. See Midcontinent Independent System Operator, Inc., 170 FERC ¶ 61,075 (2020).
In order to manage for potential forward flexibility needs, the market must ensure that online and offline flexible capacity is available to respond if needed. Hypothetically, this could occur by “repositioning the resource stack” where a fast moving (and very cheap) Resource at max could be dispatched downwards and an expensive (and slow moving) Resource near its minimum might be dispatched upwards in order to help clear sufficient flexibility to meet the product’s requirement. This repositioning behavior does not occur without adding logic (for example, a market product such as the proposed Uncertainty Reserve product). At present, a flexibility requirement is not modeled and thus there is no logic present in the market optimization that would result in commitment and dispatch that prioritized increased flexibility notwithstanding an increase in cost. This repositioning behavior would be extended into commitment decisions where the market clearing formulation may decide to commit some longer-lead Resources that appear more expensive (instead of a group of 10 small/fast/cheap Resources) in order to ensure it has enough 1-hour flexibility to meet the requirement composed of both online and offline Resources.

The two examples below compare a status quo scenario (Figure 1) with a scenario that includes an Uncertainty Reserve product (Figure 2) in order to show that the product procures additional flexibility for a cost, without harming the profit of the Resource dispatched at max in the status quo scenario. The transmission line is unconstrained in both scenarios, the system flexibility assumes a 1-hour time horizon, and the product requirement is 100 MW in the second scenario.

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Concerns around system flexibility are not limited to one hour. SPP operators monitor rolling time horizons (e.g., minutes, one hour, two hours, three hours, seven days). There is not a practical manner to represent these varied horizons in the market without modeling numerous products, each focused on a given time horizon. At present, such an undertaking would create both performance and non-reliability based system level concerns. In the future, as uncertainty “risk” continues to grow, it is possible that there will be a need to expand the time horizons that future flexibility products address. The design of the Uncertainty Reserve product proposed herein is such that the addition of additional flexibility products should be straightforward from an implementation perspective.
The scenario in Figure 3 shows the increased flexibility obtained by the Uncertainty Reserve product in comparison to the status quo “historical” case in a simulation.
involving 3/05/2018 with higher amounts of uncertainty intended to represent what a high uncertainty requirement would look like.

![3/05/2018 RTBM 1-Hour Flexibility](image)

**Figure 3: Example of Increased Flexibility**

**B. Uncertainty Reserve Will Reduce Make Whole Payments and the Impacts of Price Suppression Resulting from Out of Market Actions**

In today’s market, the Regulation and Contingency Reserve requirements only capture a portion of any uncertainty and certainly not the potentially significant variability SPP encounters on the one-hour and greater time horizon due to shifts in renewable-powered generation and other contributing factors. Historically, this has meant that, in times where there is significant variability on the grid, SPP needed an increasing amount of out-of-market commitments in order to maintain reliability. Although an Uncertainty Reserve product would not eliminate that need entirely, it can reduce MWPs by ensuring that the market clearing formulation has visibility into upcoming uncertainty and flexibility needs that will impact the system. By adding this currently un-modeled component into the market clearing formulation, the additional need for flexibility can be co-optimized with the existing system requirements.

An example of the effects that procuring an additional amount of flexibility in the market formulation has on MWPs is provided below. See Figure 4. In this example from SPP’s production systems, the simulation shows that by adding the additional flexibility requirement into the Day-Ahead Market commitment, additional capacity was procured. While this did moderately increase the Day-Ahead Market MWP, there was a significant decrease to the Real-Time MWP. This is due to the re-configuration that the clearing engine made by holding back 660 MWs of quick-starting gas units, paying those units for the Uncertainty Reserve product, and mitigating the cost of out of market real-time actions.
C. Uncertainty Reserve Will Provide Transparent Prices and a New Revenue Stream for Online and Offline Resources Eligible to Participate

There is a need for flexibility due to the evolving grid, and the most appropriate, transparent, and economic avenue to obtain this needed service is to enhance the SPP’s market formulation to explicitly model the requirement for flexibility. This will allow SPP’s Integrated Marketplace to value the service explicitly, compensate flexible resources capable of providing the service, and incentivize new market entrants to ensure their resources are capable of providing that flexibility.

A small bus example of this concept (only showing online resources) can be seen in Figure 2. Figure 5 shows the Market Clearing Price (“MCP”) from the same simulation used for the graph in Figure 3. Notice that while flexibility is available as a part of the base economic dispatch, the Uncertainty Reserve MCP remains low. However, when flexibility begins to tighten, the value of procuring that flexibility increases.
For the reasons stated and illustrated above, SPP respectfully requests that the Commission accept the Tariff revisions proposed herein as just and reasonable.

III. DESCRIPTION OF TARIFF REVISIONS

A. Definitions

1. New Definitions

SPP proposes to add the following definitions to Section 1.1 of Attachment AE of the Tariff:

Uncertainty Reserve
An Operating Reserve product procured by the Transmission Provider from the portion of a dispatchable and participating Resource’s capability that is reserved for potentially increasing net obligations for future Dispatch Intervals. The value for Resources clearing online Uncertainty Reserve is derived using loss of opportunity, similar to Ramp Capability Up. Resources capable of clearing offline Uncertainty Reserve may submit an Uncertainty Reserve Offer, and must not be scheduled to come online within the Uncertainty Reserve response time more quickly than the operator calling on the Resource in the Dispatch Interval.
Uncertainty Reserve Offer
The price at which a Resource has agreed to sell offline Uncertainty Reserve. Uncertainty Reserve Offers do not apply to online Uncertainty Reserves.\textsuperscript{22}

2. Modifications to Existing Definitions

SPP proposes to modify the following existing definitions in the Tariff.

The definition of Operating Reserve Only Resource is modified to add a reference to Uncertainty Reserve and to add the following sentence: “A Resource that cannot be cleared for dispatch or Energy will not be qualified to provide Ramp Capability Up, Ramp Capability Down, or Uncertainty Reserve.”\textsuperscript{23}

The definition of Real-Time Balancing Market ("RTBM") is modified to remove the list of Operating Reserve products and instead reference “each Operating Reserve product.”\textsuperscript{24}

The definition of Market Clearing Price ("MCP") is modified to remove the list of Operating Reserve products and instead reference “each Operating Reserve product.”\textsuperscript{25}

The definition of Operating Reserve is modified to include a reference to “Uncertainty Reserve.”\textsuperscript{26}

The definition of Resource Offer is modified to include a reference to “Uncertainty Reserve Offer.”\textsuperscript{27}

\textsuperscript{22} Proposed Tariff at Attachment AE, Section 1.1 – Definitions U.
\textsuperscript{23} Proposed Tariff at Part I, Section 1 – Definitions O.
\textsuperscript{24} Proposed Tariff at Part I, Section 1 – Definitions R.
\textsuperscript{25} Proposed Tariff at Attachment AE, Section 1.1 – Definitions M.
\textsuperscript{26} Proposed Tariff at Attachment AE, Section 1.1 – Definitions O.
\textsuperscript{27} Proposed Tariff at Attachment AE, Section 1.1 – Definitions R.
B. Attachment AE, Section 2.10.5

SPP proposes to add new Section 2.10.5 of Attachment AE titled “Uncertainty Reserve Qualified Resources”:

Uncertainty Reserve is procured from Resources to respond to potential future net obligation changes in the SPP Energy and Operating Reserve Markets. There are no specific testing requirements for a Resource to become an Uncertainty Reserve qualified Resource. A Resource that is (1) capable of following RTBM Dispatch Instruction and (2) that has the ability to increase and maintain its output for at least the duration of the Uncertainty Reserve response time (once the specified resource output is achieved), will be considered qualified to clear Uncertainty Reserve. Resources that are physically capable will make themselves available (through self-certification), but may be able to opt-out with qualification and dispatch status. The product may be provided by online resources and offline resources. Uncertainty Reserve qualified resources will offer 0 MW offline Uncertainty Reserve, when they are not capable of providing offline Uncertainty Reserve, but may provide online Uncertainty Reserve.\(^{28}\)

C. Attachment AE, Section 2.11.1

SPP proposes revisions to Section 2.11.1 of Attachment AE to include a reference to Uncertainty Reserve.\(^{29}\)

D. Attachment AE, Section 2.17

SPP proposes revisions to Section 2.17 of Attachment AE to include a reference to Uncertainty Reserve.\(^{30}\)

\(^{28}\) Proposed Tariff at Attachment AE, Section 2.10.5. SPP also updates the table of contents to Attachment AE to add Section 2.10.5 and the other new sections proposed in this filing.

\(^{29}\) Proposed Tariff at Attachment AE, Section 2.11.1(A)(2).

\(^{30}\) Proposed Tariff at Attachment AE, Section 2.17(2)(a).
E. Attachment AE, Section 3.1.4

SPP proposes revisions to Section 3.1.4 of Attachment AE to include a reference to Uncertainty Reserve. SPP also changes to the title of this section to “Operating Reserve and Instantaneous Load Capacity Requirements.”

F. Attachment AE, Section 3.1.7

SPP proposes to add new subsection E to Section 3.1.7 of Attachment AE which reads: “Uncertainty Reserve is not eligible for product substitution with other Operating Reserves.”

G. Attachment AE, Section 3.5

SPP proposes revisions to Section 3.5 of Attachment AE to include a reference to Uncertainty Reserve.

H. Attachment AE, Section 4.1

SPP proposes to add new subsection (7)(d) to Section 4.1 of Attachment AE which reads: “An Uncertainty Reserve Qualified Resource must self-certify that the Resource is capable of following RTBM Dispatch Instruction and has the ability to increase and maintain its output for at least the duration of the Uncertainty Reserve response time (once the specified resource output is achieved).” SPP also adds “Uncertainty Reserve Offers” to the list of Resource Offer parameters in Section 4.1(9).

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31 Proposed Tariff at Attachment AE, Section 3.1.4(1).
32 Proposed Tariff at Attachment AE, Section 3.1.4.
33 Proposed Tariff at Attachment AE, Section 3.1.7(E).
34 Proposed Tariff at Attachment AE, Section 3.5.
35 Proposed Tariff at Attachment AE, Section 4.1(7)(d).
36 Proposed Tariff at Attachment AE, Section 4.1(9).
I. Attachment AE, Section 4.1.1

SPP proposes revisions to Section 4.1.1 of Attachment AE to add an Uncertainty Reserve Offer cap of $1000/MW\textsuperscript{37} and an Uncertainty Reserve Offer floor of $0/MW.\textsuperscript{38}

J. Attachment AE, Section 5.1.3

SPP proposes revisions to Section 5.1.3(A)(1) of Attachment AE to add the words “or Uncertainty Reserves.”\textsuperscript{39} SPP also adds new subsection 5.1.3(A)(1)(i) which reads: “Cleared Uncertainty Reserve MWs represent only those MWs cleared to meet the Uncertainty Reserve requirement.”\textsuperscript{40}

K. Attachment AE, Section 6.2.2

SPP proposes revisions to Section 6.2.2 of Attachment AE include a reference to Uncertainty Reserve.\textsuperscript{41}

L. Attachment AE, Section 6.2.3

SPP proposes revisions to Section 6.2.3 of Attachment AE to include a reference to Uncertainty Reserve.\textsuperscript{42} SPP also adds new subsection (b)(vi) which reads:

\textsuperscript{37} Proposed Tariff at Attachment AE, Section 4.1.1(14). Initially, SPP considered a $100/MW offer cap consistent with other products. During the design phase, it was observed that in some instances some Resources had mitigated offers greater than the $100/MW offer cap. Such Resources would, essentially, be forced to submit offers that were less than the sum of their Start-Up Offer and No-Load Offer costs, leaving the Resources ineligible for MWPs. Discussions with the SPP Market Monitoring Unit resulted in the proposed offer cap of $1000/MW.

\textsuperscript{38} Proposed Tariff at Attachment AE, Section 4.1.1(15).

\textsuperscript{39} Proposed Tariff at Attachment AE, Section 5.1.3(A)(1).

\textsuperscript{40} Proposed Tariff at Attachment AE, Section 5.1.3(A)(1)(i).

\textsuperscript{41} Proposed Tariff at Attachment AE, Section 6.2.2(1).

\textsuperscript{42} Proposed Tariff at Attachment AE, Section 6.2.3(1)(b).
“Cleared Uncertainty Reserve MWs represent only those MWs cleared to meet the Uncertainty Reserve requirement.”

M. Attachment AE, Section 8.3.4

SPP proposes revisions to Section 8.3.4 of Attachment AE to add an additional set of constraints which apply on both a system-wide basis and Reserve Zone basis. Specifically, SPP adds the Uncertainty Reserve constraint which is set equal to the Uncertainty Reserve requirement. SPP also proposes to add the Uncertainty Reserve MCP which is equal to the Shadow Price for the system-wide Uncertainty Reserve constraint in Section 8.3.4(2).

SPP proposes to add new subsection (2)(f) to Section 8.3.4.2 to include the rules for the calculation of Uncertainty Reserve Scarcity Pricing:

(f) Uncertainty Reserve – SPP calculates and posts Uncertainty Reserve Scarcity Pricing in accordance with the following rules:

1. The Uncertainty Reserve Demand Curve prices are determined by applying a factor to the Regulation Base Demand Price such that the magnitude of the Uncertainty Reserve Demand Curve price is less than the Regulation Base Demand Price.

2. The Demand Curve levels for Uncertainty Reserve will be equal to:
   a. Shortages up to or equal to 5% of the requirement will equal, to the nearest dollar, 0.05 times the Regulation Base Demand Price.
   b. Shortages greater than 5% but less than or equal to 10% of the requirement will equal, to the nearest

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43 Proposed Tariff at Attachment AE, Section 6.2.3(1)(b)(vii).
44 Proposed Tariff at Attachment AE, Section 8.3.4(1)(g).
45 Proposed Tariff at Attachment AE, Section 8.3.4(2)(g).
46 The Uncertainty Reserve Demand Curve is designed to ensure that the Uncertainty Reserve product does not become more valuable than regulation in some scenarios. This is accomplished by starting with the lowest step in the Regulation-Up curve and then moving downwards in increments.
dollar, 0.35 times the Regulation Base Demand Price.

c. Shortages greater than 10% but less than or equal to 15% of the requirement will equal, to the nearest dollar, 0.55 times the Regulation Demand Price.

d. Shortages greater than 15% but less than or equal to 20% of the requirement will equal, to the nearest dollar, 0.70 times the Regulation Demand Price.

e. Shortages greater than 20% of the requirement will equal, to the nearest dollar, 0.95 times the Regulation Demand Price.

3. The minimum amount for the Uncertainty Demand Curve prices will be limited to $10.\textsuperscript{47}

SPP also proposes to add new subsection (i) to Section 8.3.4.2 of Attachment AE which reads: “If there is a system-wide shortage of Uncertainty Reserve, the Uncertainty Reserve MCP will be set equal to the applicable Uncertainty Reserve Demand Curve price. The Uncertainty Reserve Demand Curve price will be reflected in the LMP.”\textsuperscript{48}

N. Attachment AE, Section 8.5.9

SPP proposes revisions to Section 8.5.9(3)(c) of Attachment AE to add “Uncertainty Reserve” in two locations.\textsuperscript{49} SPP also revises Section 8.5.9(4)(b)(ii) of Attachment AE to add a reference to Section 8.5.29 of Attachment AE.\textsuperscript{50}

O. Attachment AE, Section 8.5.29

SPP proposes to add new Section 8.5.29 of Attachment AE to describe the calculation of the Day-Ahead Market payment for cleared Uncertainty Reserve.\textsuperscript{51}

\textsuperscript{47} Proposed Tariff at Attachment AE, Section 8.3.4.2(2)(f).

\textsuperscript{48} Proposed Tariff at Attachment AE, Section 8.3.4.2(4)(i).

\textsuperscript{49} Proposed Tariff at Attachment AE, Section 8.5.9(3)(c).

\textsuperscript{50} Proposed Tariff at Attachment AE, Section 8.5.9(4)(b)(ii).

\textsuperscript{51} Proposed Tariff at Attachment AE, Section 8.5.29.
P. Attachment AE, Section 8.5.30

SPP proposes to add new Section 8.5.29 of Attachment AE to describe the Day-Ahead Market charge for Uncertainty Reserve procurement costs.\(^{52}\)

Q. Attachment AE, Section 8.6.5

SPP proposes to add new subsection (3) to Section 8.6.5(3)(e)(iii) of Attachment AE which reads: “For any RUC make whole payment eligibility period for which the commitment is made in conjunction with RTBM offline Uncertainty Reserve clearing.”\(^{53}\)

SPP proposes revisions to Section 8.6.5(3)(l) of Attachment AE to include a reference to Uncertainty Reserve.\(^{54}\)

SPP proposes to revise Section 8.6.5(4)(b) as follows:

An Asset Owner’s RUC Make Whole Payment Cost Amount for each eligible Resource is equal to the sum for all Dispatch Intervals in the RUC commitment of:

(i) No-Load Offer used to make the RUC commitment decision, less any Day-Ahead Market No-Load from an MCR resulting from a different Day-Ahead Market committed configuration where the No-Load Offer shall be included as zero for Dispatch Intervals constituting the larger of the Uncertainty Reserve response time or Minimum Run Time of a RUC commitment made in conjunction with offline Uncertainty Reserve clearing;

(ii) Energy cost at minimum output as calculated from the Energy Offer Curve used to make the commitment decision where this Energy cost at minimum shall be included as zero for Dispatch Intervals constituting the larger of the Uncertainty Reserve response time or Minimum Run Time of a RUC commitment made in conjunction with offline Uncertainty Reserve clearing.\(^{55}\)

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\(^{52}\) Proposed Tariff at Attachment AE, Section 8.5.30.

\(^{53}\) Proposed Tariff at Attachment AE, Section 8.6.5(3)(e)(iii)(3).

\(^{54}\) Proposed Tariff at Attachment AE, Section 8.6.5(3)(l).

\(^{55}\) Proposed Tariff at Attachment AE, Section 8.6.5(4)(b)(i)-(ii).
SPP proposes to add new subsection (xii) to Section 8.6.5(4)(c) of Attachment AE which reads: “Real-Time Uncertainty Reserve revenue as calculated under Section 8.6.29 of this Attachment AE.”

R. Attachment AE, Section 8.6.29

SPP proposes to add new Section 8.6.29 of Attachment AE to describe the calculation of an RTBM payment or charge for deviations between cleared RTBM Uncertainty Reserve and cleared Day-Ahead Market Uncertainty Reserve.

S. Attachment AE, Section 8.6.30

SPP proposes to add new Section 8.6.30 of Attachment AE to describe how the RTBM payment or charge for Uncertainty Reserve will be calculated by Asset Owner at each Settlement Location for purposes of funding payments made under Section 8.6.29 of Attachment AE.

T. Attachment AE, Section 8.6.31

SPP proposes to add new Section 8.6.31 of Attachment AE to describe how the RTBM payment or charge will be calculated at each Resource Settlement Location for each Asset Owner for each Dispatch Interval when a Resource with cleared RTBM Uncertainty Reserve does not operate in a responsive manner.

U. Attachment AE, Section 8.6.32

SPP proposes to add new Section 8.6.32 of Attachment AE to describe how the RTBM payment or charge will be calculated for each Asset Owner at each Settlement Location for each hour in order to distribute the funds collected under Section 8.6.31 of Attachment AE.

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56 Proposed Tariff at Attachment AE, Section 8.6.5(4)(c)(xii).
57 Proposed Tariff at Attachment AE, Section 8.6.29.
58 Proposed Tariff at Attachment AE, Section 8.6.30.
59 Proposed Tariff at Attachment AE, Section 8.6.31.
60 Proposed Tariff at Attachment AE, Section 8.6.32.
V. Attachment AF, Section 3

SPP proposes revisions to Section 3.4 of Attachment AF to insert new subsections G and H:

G. Ramp Capability Up, Ramp Capability Down, and online Uncertainty Reserve products will not require mitigated offers, as the cost of these products shall be the marginal cost of lost opportunity and not participant Offers.

H. The mitigated offline Uncertainty Reserve Offers shall not exceed the costs that shall not be eligible for reimbursement through a make whole payment for Resources that clear offline Uncertainty Reserve, and are committed to provide energy as a result of that clearing, as described in Section 8.6.5 of Attachment AE of this Tariff. These costs shall be amortized over the Resource’s expected Uncertainty Reserve megawatts and Uncertainty Reserve response time:

\[
\text{Offline Uncertainty Reserve} \ ($/\text{MWh}) = \frac{\text{Start-Up Costs} \ ($/\text{Start}) + \text{No-Load Costs} \ ($/\text{hour}) \times \text{Max(Uncertainty Reserve response time, Minimum Run Time)} \ (\text{hours}) + \text{Minimum Energy Costs during the larger of the Uncertainty Reserve response time and Minimum Run Time} \ ($/\text{Start})}{(\text{Expected Uncertainty Megawatts} \times \text{Uncertainty Reserve response time (hours)})}.
\]

Expected uncertainty megawatts are derived from the total rampable capacity that an offline resource can provide, from an offline state, during the Uncertainty Reserve response time. This includes the ramp provided to reach the Minimum Economic Capacity Operating Limit, plus any ramp that can be provided to the market during the remaining Uncertainty Reserve response time. For example, if a resource has a 60 MWh ramp rate, a Minimum Economic Capacity Operating Limit of 20 megawatts, a Maximum Economic Capacity Operating Limit of 100 megawatts, and a combined Start-Up and Sync-To-Min Time of 40 minutes, then the expected Uncertainty Reserve megawatts will be 40 megawatts when the Uncertainty Reserve response time is one hour. In this example, 20 megawatts came from the resource reaching its economic minimum limit, then 20 megawatts came from the 20 minutes remaining in the Uncertainty Reserve response time [1 hour response time - (40 minutes)]
Start-Up Time+ Sync-to-min)] multiplied by the one megawatt per minute ramp rate.\footnote{Proposed Tariff at Attachment AF, Section 3.4(G)-(H). SPP re-numbers the remaining subsections in order to accommodate the addition of the new subsections.}

W. Attachment AO

SPP proposes revisions to Addenda 1 and 2 to Attachment AO to include “Uncertainty Reserve” in Section 2(c).\footnote{Proposed Tariff at Attachment AO, Addenda 1 and 2, Section 2(c).}

IV. EFFECTIVE DATE AND REQUEST FOR WAIVER

Due to scheduling and resource constraints with projects already in the production and software development queues, SPP is requesting an effective date of “12/31/9998” for the Tariff Records included with this filing. The expected effective date of the Tariff revisions included herein is in the fourth quarter of 2022, which is expected to be more than 120 days after filing. Therefore, SPP requests waiver of the Commission’s notice requirements.\footnote{18 C.F.R. § 35.3(a)(1).} Good cause exists for the proposed revisions to be effective in the fourth quarter of 2022 in accordance with the Commission’s waiver of notice requirement codified in Section 35.11 of the Commission’s regulations\footnote{18 C.F.R. § 35.11.} because SPP will need a number of months to develop, test, and implement the software system changes for the Tariff revisions proposed herein. SPP requests the Commission issue an order by April 28, 2022 to allow SPP sufficient time to make the necessary software changes prior to implementation.
V. ADDITIONAL INFORMATION

A. Documents submitted with this filing:

In addition to this Transmittal Letter, Clean and Redlined Tariff revisions under the Sixth Revised Volume No. 1.65

B. Service:

SPP has electronically served a copy of this filing on all its Members, Transmission Customers and Market Participants. A complete copy of this filing will be posted on the SPP web site, www.spp.org, and is also being served on all affected state commissions.

C. Requisite agreements:

There are none.

D. Communications

Correspondence and communications with respect to this filing should be sent to, and SPP requests the Secretary to include on the official service list, the following:

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65 The table of contents for Attachment AE included in this filing contains language in italics indicating language pending before the Commission in Docket No. ER22-684-000.
VI. CONCLUSION

For all of the foregoing reasons, SPP respectfully requests that the Commission issue an order accepting the Tariff revisions proposed herein as soon as practicable. SPP will submit a filing with the Commission specifying a precise effective date when that date is known and not less than 30 days before that date.

Respectfully submitted,

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O - Definitions

OATT: See “Tariff.”

Open Access Same-Time Information System (OASIS): The information system and Internet location where the Transmission Provider posts the information required by 18 C.F.R. § 37 of the Commission’s regulations, and where the Transmission Provider may also post the information required to be posted on its Internet website by 18 C.F.R. § 358 of the Commission’s regulations.

Operating Reserve Only Resource: A Resource that cannot be cleared or dispatched for Energy that is qualified to provide any or all of the Operating Reserve products: Regulation-Up, Regulation-Down, Spinning Reserve, Supplemental Reserve, Ramp Capability Up, Ramp Capability Down, or Uncertainty Reserve. A Resource that cannot be cleared for dispatch or Energy will not be qualified to provide Ramp Capability Up, Ramp Capability Down, or Uncertainty Reserve.

Oversight Committee: The organizational group defined in Section 6.4 of the SPP Bylaws.
R - Definitions

**Real-Time:** As defined in Attachment AE to this Tariff.

**Real-Time Balancing Market ("RTBM"):** The market operated by the Transmission Provider continuously in real-time to balance the system through deployment of Energy and to clear each Operating Reserve product.

**Receiving Party:** The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

**Region-wide Annual Transmission Revenue Requirement:** The sum of the annual transmission revenue requirements as set forth in Attachment H, Table 2-A and Table 2-B.

**Region-wide Charge:** Regional component of the charge assessed by the Transmission Provider in accordance with Schedule 11 to recover the Region-wide Annual Transmission Revenue Requirement.

**Region-wide Load Ratio Share:** For application to Section I, Table 2-A of Attachment H, the ratio of a Network Customer’s or Transmission Owner’s Resident Load to total Resident Load in Zones 1 through 18, computed in accordance with Section II.B to Schedule 11 of this Tariff, and calculated on a calendar year basis for the prior calendar year. For application to Section I, Table 2-B of Attachment H, the ratio of a Network Customer's or Transmission Owner’s Resident Load to total Resident Load in the SPP Region, with both numerator and denominator limited to Resident Loads subject to the Region-wide Charge, computed in accordance with Section II.C to Schedule 11 of this Tariff, and calculated on a calendar year basis for the prior calendar year. Customer loads used to determine the Region-wide Load Ratio Share shall be adjusted for real power losses in accordance with the provisions set out in Section 28.5 of this Tariff.
**Region-wide Rate:** Regional component of the rate per kW of Reserved Capacity assessed by the Transmission Provider in accordance with Schedule 11 to recover the Region-wide Annual Transmission Revenue Requirement.

**Regional State Committee:** A voluntary organization comprised of one designated commissioner from each participating state regulatory commission having jurisdiction over an SPP Member, established to collectively provide both direction and input on all matters pertinent to the participation of the Members in SPP pursuant to the SPP Bylaws.

**Regional Transmission Group (RTG):** A voluntary organization of Transmission Owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

**Reliability Unit Commitment:** As defined in Attachment AE of this Tariff.

**Reserve Sharing System:** The Transmission Provider’s computer system that receives and records contingency events and requests for assistance by Reserve Sharing Group members, calculates and communicates the appropriate reserve capacity obligations and reserve energy responsibilities for events to all Reserve Sharing Group members and creates applicable Energy schedules for deployment by the Reserve Sharing Group members.

**Reserved Capacity:** The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

**Resident Load:** The load specified in Section 41 of the Tariff.
**Resource:** An asset that injects energy into the transmission grid or reduces the withdrawal of energy from the transmission grid including a Demand Response Resource, a Variable Energy Resource, a Dispatchable Resource, External Resource, External Dynamic Resource and a Quick-Start Resource.

**Revenue Requirements and Rates File (RRR File):** A file posted on the SPP website as a reference to: (i) Annual Transmission Revenue Requirements (ATRRs) for Network Integration Transmission Service, as referenced in Attachment H to this Tariff; (ii) Base Plan ATRR allocation; (iii) allocation factors for Base Plan funded projects; (iv) notes on the calculation of Base Plan ATRR amounts on a Region-wide and Zonal basis; (v) ATRR reallocation for Balanced Portfolio projects; (vi) the calculation of Base Plan Point-To-Point Transmission Service rates on a Region-wide and Zonal basis in accordance with Schedule 11; and (vii) the rates for Point-To-Point Transmission Service as referenced in Attachment T in accordance with Schedules 7 and 8.
ATTACHMENT AE
INTEGRATED MARKETPLACE
### Attachment AE

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Addendum 2 Bilateral Settlement Schedule Example System Power Sale
1.1 Definitions M

Market Clearing Price (“MCP”)
The price used for settlements of an Operating Reserve product in each Reserve Zone. A separate price is calculated for each Operating Reserve product.

Market Flow
The aggregate Megawatt flow on a Coordinated Flowgate or a Reciprocal Coordinated Flowgate caused by the Real-Time Balancing Market.

Market Participant
As defined in Section 1 of the Tariff.

Market Storage Resource (“MSR”)
An ESR that registers consistent with the requirements under Section 2.17 of this Attachment AE.

Marginal Congestion Component (“MCC”)
The calculated portion of the Locational Marginal Price at a Settlement Location representing transmission congestion costs between that Settlement Location and a reference location as calculated under Section 8.3 of this Attachment AE.

Marginal Loss Component (“MLC”)
The calculated portion of the Locational Marginal Price at a Settlement Location representing marginal loss costs between that Settlement Location and a reference location as calculated under Section 8.3 of this Attachment AE.

Maximum Charge Limit
The maximum MW level that an MSR is able to withdraw from the grid during normal operating conditions.

Maximum Charge Time
The maximum duration of time that an MSR is able to withdraw from the grid.

**Maximum Discharge Limit**
The maximum MW level that an MSR is able to inject into the grid used during normal operating conditions.

**Maximum Discharge Time**
The maximum duration of time that an MSR is able to inject into the grid.

**Maximum Economic Capacity Operating Limit**
An economic MW level at or below a Resource’s Maximum Normal Capacity Operating Limit used for constraining Energy dispatch and Contingency Reserve clearing during normal system conditions.

**Maximum Emergency Capacity Operating Limit**
The maximum Megawatt level at which a Resource other than a Block Demand Response Resource may operate under Emergency Conditions.

**Maximum Emergency Charge Limit**
The maximum MW level that an MSR is able to withdraw from the grid during an Emergency Condition.

**Maximum Emergency Discharge Limit**
The maximum MW level that an MSR is able to inject into the grid during an Emergency Condition.

**Maximum Normal Capacity Operating Limit**
The maximum Megawatt level at which a Resource may operate continuously.
Maximum Off-line Supplemental Reserve Response Limit
The maximum amount of off-line Supplemental Reserve that can be provided by a Resource.

Maximum Regulation Capacity Operating Limit
The maximum Megawatt level at which a Regulation Qualified Resource, a Regulation-Up Qualified Resource or a Regulation-Down Qualified Resource may operate while providing Regulation Deployment.

Maximum State of Charge
The maximum State of Charge that should not be exceeded.

Megawatt (“MW”)
A measurement unit of the instantaneous demand for Energy.

Meter Agent
An entity responsible for collecting load and Resource data associated with identified Meter Settlement Locations within a Settlement Area for the purpose of energy accounting that impacts market settlements.

Meter Data Submittal Location
One or more Meter Settlement Locations contained within a single Settlement Area for which meter data is submitted to the Transmission Provider by the Meter Agent for settlement purposes.

Meter Settlement Location
The point at which a Market Participant’s registered load and Resources interchange Energy with the Real-Time Balancing Market.

Minimum Charge Limit
The minimum MWs level an MSR is able to withdraw from the grid during normal operating conditions.
Minimum Charge Time
The minimum duration of time an MSR is able to withdraw from the grid.

Minimum Discharge Limit
The minimum MW level that an MSR is able to inject into the grid during normal operating conditions.

Minimum Discharge Time
The minimum duration of time that an MSR is able to inject into the grid.

Minimum Economic Capacity Operating Limit
A Megawatt level at or above a Resource’s Minimum Normal Capacity Operating Limit used for energy dispatch at a minimum level during normal operating conditions.

Minimum Emergency Capacity Operating Limit
The minimum Megawatt level at which a Resource other than a Block Demand Response Resource may operate under Emergency Conditions.

Minimum Emergency Charge Limit
The minimum MW level that an MSR is able to withdraw from the grid during an Emergency Condition.

Minimum Emergency Discharge Limit
The minimum MW level that an MSR is able to inject into the grid during an Emergency Condition.

Minimum Normal Capacity Operating Limit
The minimum Megawatt level at which a Resource may operate continuously.

Minimum Regulation Capacity Operating Limit
The minimum Megawatt level at which a Regulation Qualified Resource, a Regulation-Up Qualified Resource or a Regulation-Down Qualified Resource may operate while providing Regulation Deployment.

**Minimum Run Time**
The minimum length of time a Resource must run from the time the Resource is put online to the time the Resource is shut-down.

**Minimum State of Charge**
The minimum State of Charge that should be maintained.

**Min-To-Off Time**
The time for a Resource to de-synchronize from the grid starting from the Resource’s Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Minimum Charge Limit, as applicable.

**Most Severe Single Contingency**
The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority’s area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of an RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

**Multi-Configuration Resource (“MCR”)**
A combined cycle Resource registered consistent with the offer submission option as defined under Section 4.1.2.2(4) of this Attachment AE.

**Multi-Day Reliability Assessment**
The process to assess Resource adequacy for the Operating Day, commit Resources with long Start-Up Times that cannot be considered as part of the Day-Ahead Market or Day-Ahead Reliability Unit Commitment, and communicate commitment of such Resources as necessary.
1.1 Definitions

Offer
A commitment to sell (i) a quantity of Energy at a specific minimum price that includes a Resource Offer, a Virtual Energy Offer or an Import Interchange Transaction Offer, or (ii) a quantity of Transmission Congestion Rights at a specific minimum price, where such quantities may be submitted in 0.1 MW increments.

Off-Peak
As defined in Schedule 1 of the Tariff.

On-Peak
As defined in Schedule 1 of the Tariff.

Operating Day
A daily period beginning at midnight.

Operating Hour
A sixty (60) minute period of time during the Operating Day corresponding to a clock hour typically expressed as hour-ending.

Operating Reserve
Resource capacity required to provide for Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, Ramp Capability Down, and Uncertainty Reserve for reasons including, but not limited to; load forecasting error, instantaneous load changes, Variable Energy Resource forecast error, and equipment forced outages.

Operating Tolerance
The Megawatt range of actual Resource output above and below the Resource’s average Setpoint Instruction over the Dispatch Interval where the Resource will not be subject to charges associated with Uninstructed Resource Deviation.
Out-of-Merit Energy (OOME)

(a) A Dispatch Instruction from the Transmission Provider to address an Emergency Condition or reliability issue that the market systems cannot resolve, (b) a Dispatch Instruction from a local transmission operator to address a Local Emergency Condition, or (c) a non-Energy manual exclusion, by the Transmission Provider, of a Resource from providing Operating Reserves after the Day-Ahead Market clears.
1.1 Definitions R

**Ramp Capability Down**
An Operating Reserve product, procured by the Transmission Provider from a Resource capable of following Setpoint Instructions, that is reserved to provide downward flexibility during periods in which net obligations decrease in future Dispatch Intervals. There is no explicit offer for this product. The value is derived using loss of opportunity.

**Ramp Capability Up**
An Operating Reserve product, procured by the Transmission Provider from a Resource capable of following Setpoint Instructions, that is reserved to provide upward flexibility during periods in which net obligations increase in future Dispatch Intervals. There is no explicit offer for this product. The value is derived using loss of opportunity.

**Ramp-Rate-Down**
A curve specifying MW/minute ramp rates applicable between Resource operating ranges that is used to dispatch Resources in the down direction. For MSRs, Ramp-Rate-Down is the rate at which a MSR can move from zero output to Maximum Charge Limit, which is represented as a negative (-) value for the MW breakpoint. This rate also represents the rate at which the MSR can move from Maximum Discharge Limit to zero output.

**Ramp-Rate-Up**
A curve specifying MW/minute ramp rates applicable between Resource operating ranges that is used to dispatch Resources in the up direction. For MSRs, Ramp-Rate-Up is the rate at which a MSR can move from zero output to Maximum Discharge Limit. This rate also represents the rate at which the MSR can move from Maximum Charge Limit, which is represented as a negative (-) value for the MW breakpoint, to zero output.

**Real-Time**
The continuous time period during which the Real-Time Balancing Market is operated.
Real-Time Balancing Market (“RTBM”)
As defined in Section 1 of the Tariff.

Real-Time Capability
The amount (MW) of real power output the Resource is capable of instantaneously producing, excluding any dispatch, deployment, or curtailment instructions.

Real-Time Load Ratio Share
The sum of a Market Participant’s Reported Load, Self-Charging MSRs, and Export Interchange Transactions at all Settlement Locations divided by the sum of all Market Participants’ Reported Load, Self-Charging MSRs, and Export Interchange Transactions at all Settlement Locations for a given hour.

Reciprocal Coordinated Flowgate
A Coordinated Flowgate defined within a joint operating agreement between SPP and another transmission provider as being affected by the transmission of Energy on both of their respective transmission systems.

Reference Bus
The location on the Transmission System relative to which all mathematical quantities, including shift factors and penalty factors relating to physical operation, will be calculated.

Regulation Deployment
The utilization of Regulation-Up Service and/or Regulation-Down Service through automatic generation control equipment to automatically and continuously adjust Resource output to balance the real power requirements of the SPP Balancing Authority Area.

Regulation-Down
An Operating Reserve product procured by the Transmission Provider from qualified Resources that reduce their energy output (or increase consumption of the Demand Response Load
associated with a qualified Dispatchable Demand Response Resource) in response to a Regulation Deployment instruction from the Transmission Provider.

**Regulation-Down Mileage Factor**
A factor determined through historical Regulation Deployment analysis that represents the ratio of the Transmission Provider’s total Instructed Regulation-Down Mileage to the Transmission Provider’s total cleared Regulation-Down Service. The Regulation-Down Mileage Factor shall initially be set equal to 1.0 and shall be updated periodically pursuant to the Market Protocols.

**Regulation-Down Mileage Offer**
The price at which a Regulation Qualified Resource or a Regulation-Down Qualified Resource has agreed to sell Expected Regulation-Down Mileage.

**Regulation-Down Offer**
The price at which a Regulation Qualified Resource or a Regulation-Down Qualified Resource has committed to sell Regulation-Down.

**Regulation-Down Qualified Resource**
A Resource that has met the requirements to be eligible to submit Regulation-Down Offers and Regulation-Down Mileage Offers into the Energy and Operating Reserve Markets.

**Regulation-Down Scarcity Factor**
A multiplier used to define shortage regions of Regulation-Down and the appropriate scarcity price value associated with the shortage.

**Regulation-Down Service**
The provision of Actual Regulation-Down Mileage associated with cleared Regulation-Down Service MW in response to Regulation Deployment instructions.

**Regulation-Down Service Offer**
The sum of (i) a Resource’s Regulation-Down Mileage Offer multiplied by the Regulation-Down Mileage Factor and (ii) that Resource’s Regulation-Down Offer.

**Regulation Mileage Operating Tolerance**
The allowable percentage deviation below a Resource’s Instructed Regulation-Up Mileage and/or Instructed Regulation-Down Mileage over the Dispatch Interval where the Resource will settle based upon Instructed Regulation-Up Mileage and/or Instructed Regulation-Down Mileage versus Actual Regulation-Up and/or Actual Regulation-Down Mileage. Such percentage is set at 5%.

**Regulation Qualified Resource**
A Resource that has met the requirements to be eligible to submit Regulation-Up Offers, Regulation-Up Mileage Offers, Regulation-Down Offers and Regulation-Down Mileage Offers into the Energy and Operating Reserve Markets.

**Regulation Response Time**
The maximum amount of time allowed for a Resource to move its output from zero (0) Regulation Deployment to the full amount of Regulation-Up cleared or to move from zero (0) Regulation Deployment to the full amount of Regulation-Down cleared.

**Regulation-Up**
An Operating Reserve product procured by the Transmission Provider from qualified Resources that increase their energy output (or reduce consumption of the Demand Response Load associated with a qualified Dispatchable Demand Response Resource) in response to a Regulation Deployment instruction from the Transmission Provider.

**Regulation-Up Mileage Factor**
A factor determined through historical Regulation Deployment analysis that represents the ratio of the Transmission Provider’s total Instructed Regulation-Up Mileage to the Transmission Provider’s total cleared Regulation-Up Service. The Regulation-Up Mileage Factor shall initially be set equal to 1.0 and shall be updated periodically pursuant to the Market Protocols.
**Regulation-Up Mileage Offer**
The price at which a Regulation Qualified Resource or a Regulation-Up Qualified Resource has agreed to sell Expected Regulation-Up Mileage.

**Regulation-Up Offer**
The price at which a Regulation Qualified Resource or a Regulation-Up Qualified Resource has committed to sell Regulation-Up.

**Regulation-Up Qualified Resource**
A Resource that has met the requirements to be eligible to submit Regulation-Up Offers and Regulation-Up Mileage Offers into the Energy and Operating Reserve Markets.

**Regulation-Up Scarcity Factor**
A multiplier used to define shortage regions of Regulation-Up and the appropriate scarcity price value associated with the shortage.

**Regulation-Up Service**
The provision of Actual Regulation-Up Mileage associated with cleared Regulation-Up Service MW in response to Regulation Deployment instructions.

**Regulation-Up Service Offer**
The sum of (i) a Resource’s Regulation-Up Mileage Offer multiplied by the Regulation-Up Mileage Factor and (ii) that Resource’s Regulation-Up Offer.

**Reliability Unit Commitment (“RUC”)**
The process performed by the Transmission Provider to assess resource and Operating Reserve adequacy for the Operating Day, commit or de-commit resource as necessary, and communicate commitment or de-commitment of Resources to the appropriate Market Participants as necessary.
Reliability Unit Commitment Period ("RUC Commitment Period")
The contiguous period of time between a Resource’s Reliability Unit Commitment Commit Time and Reliability Unit Commitment De-Commit Time.

Reported Load
A Market Participant's actual value of energy withdrawn from the Transmission System at a Settlement Location adjusted as described under Section 8.6.1.1 of Attachment AE and further adjusted, if necessary, to account for distribution system losses between the actual metering point and the Transmission System Settlement Location as described under Appendix D of the Market Protocols.

Reservation Capacity
The reservation Megawatt between a specified source and sink associated with SPP Transmission Service.

Reserve Sharing Event
A request for assistance to deploy Contingency Reserve by any member of the Reserve Sharing Group following the sudden loss of a Resource.

Reserve Sharing Group
A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority’s use in recovering from contingencies within the group.

Reserve Zone
A zone containing a specific group of Price Nodes for which a minimum and maximum Operating Reserve requirement is calculated.

Resettlement
The settlement of an Operating Day subsequent to the posting of the S120 Scheduled Settlement Statement for that Operating Day.
**Residual Load**
Settlement Area Net Load less all other directly metered Reported Load within the Settlement Area.

**Resource**
As defined in Part I, Section 1 of this Tariff.

**Resource Hub**
A Settlement Location consisting of an aggregation of Resource Price Nodes developed for financial and trading purposes.

**Resource Offer**
For a Resource, the combination of its Start-Up Offer, No-Load Offer, Energy Offer Curve, Transition State Offer, Regulation-Up Service Offer, Regulation-Down Service Offer, Spinning Reserve Offer, Supplemental Reserve Offer, Uncertainty Reserve Offer, and Resource physical operating parameters.
1.1 Definitions U

Uncertainty Reserve
An Operating Reserve product procured by the Transmission Provider from the portion of a dispatchable and participating Resource’s capability that is reserved for potentially increasing net obligations for future Dispatch Intervals. The value for Resources clearing online Uncertainty Reserve is derived using loss of opportunity, similar to Ramp Capability Up. Resources capable of clearing offline Uncertainty Reserve may submit an Uncertainty Reserve Offer, and must not be scheduled to come online within the Uncertainty Reserve response time more quickly than the operator calling on the Resource in the Dispatch Interval.

Uncertainty Reserve Offer
The price at which a Resource has agreed to sell offline Uncertainty Reserve. Uncertainty Reserve Offers do not apply to online Uncertainty Reserves.

Uninstructed Resource Deviation (“URD”)
The Megawatt amount by which a Resource’s actual output in a Dispatch Interval is above or below that Resource’s average Setpoint Instruction in the Dispatch Interval.

Unused Regulation-Down Mileage
The amount calculated under Section 8.6.2 of this Attachment AE.

Unused Regulation-Up Mileage
The amount calculated under Section 8.6.2 of this Attachment AE.
2.10.5 Uncertainty Reserve Qualified Resources

Uncertainty Reserve is procured from Resources to respond to potential future net obligation changes in the Energy and Operating Reserve Markets. There are no specific testing requirements for a Resource to become an Uncertainty Reserve qualified Resource. A Resource that is (1) capable of following RTBM Dispatch Instruction and (2) that has the ability to increase and maintain its output for at least the duration of the Uncertainty Reserve response time (once the specified resource output is achieved), will be considered qualified to clear Uncertainty Reserve. Resources that are physically capable will make themselves available (through self-certification), but may be able to opt-out with qualification and dispatch status. The product may be provided by online resources and offline resources. Uncertainty Reserve qualified resources will offer 0 MW offline Uncertainty Reserve, when they are not capable of providing offline Uncertainty Reserve, but may provide online Uncertainty Reserve.
2.11.1  Day-Ahead Market

A. Each Market Participant must satisfy the must offer obligation for an Asset Owner as set forth in Section 2.11.1(B) of this Attachment AE based on the following criteria:

(1) A Market Participant’s load for an Asset Owner for purposes of this section shall be equal to that Market Participant’s maximum hourly Reported Load for an Asset Owner for the Operating Day. Such Asset Owner’s Reported Load shall include load registered as described under Section 2.2(11) of this Attachment AE, where the buyer’s Reported Load shall be reduced by the amount of the buyer’s load registered by the seller and the seller’s Reported Load shall be increased by the amount of the buyer’s load registered by the seller. If an MSR is Self-Charging during the maximum Reported Load hour, the Market Participant’s available generation that is used to satisfy the must offer obligation is reduced by the Self-Charging MW.

(2) A Market Participant’s daily Operating Reserve obligation for an Asset Owner shall be equal to the sum of that Market Participant’s maximum daily Regulation-Up Service, Regulation-Down Service, Contingency Reserve, Ramp Capability Up, Ramp Capability Down, and Uncertainty Reserve obligations for an Asset Owner as estimated by the Transmission Provider in accordance with Section 3.1.4(3) of this Attachment AE.

(3) A Market Participant may satisfy this requirement by offering Resources for an Asset Owner with a commitment status indicating either that the Market Participant is self-committing the Resource, the Resource may be committed by the Transmission Provider, or the Resource may be committed by the Transmission Provider only to alleviate an anticipated Emergency Condition or Local Reliability Issue, as specified in Sections 4.1(10)(a), 4.1(10)(b), and 4.1(10)(c) of the Attachment AE.

(4) A Market Participant’s net resource capacity for an Asset Owner, for purposes of this section shall include:

i. Offered capacity by Resources identified in Section 2.11.1(A)(3) of Attachment AE less the Operating Reserve obligation identified in Section 2.11.1(A)(2) of Attachment AE; and
ii. Firm power purchases less firm power sales, except that, if the seller has registered the buyer’s load associated with a firm power sale as described in Section 2.2(11) of this Attachment AE, such firm power sale shall not act to increase the buyer’s net resource capacity or act to reduce the seller’s net resource capacity. For purposes of this Section 2.11.1 of this Attachment AE firm power purchases and firm power sales shall mean sales and purchases that are deliverable with transmission service comparable to Firm Point-To-Point Transmission Service or Firm Network Integration Transmission Service with the supplier assuming the obligation to provide both capacity and energy. Additionally, firm power purchases shall include an Asset Owner’s share of a Jointly Owned Unit to the extent that such shares have not been registered as separate Resources either under Jointly Owned Unit individual Resource option as described under Section 2.2(4) of this Attachment AE, or under Combined Interest Resource modeling as described under Section 2.2(18) of this Attachment AE.

In order to verify firm power purchases and firm power sales, supporting documentation must be provided to the Market Monitor upon request. Market Participants have the option to input information regarding firm power purchases and firm power sales into the Market Monitor website. If no information is input into this website, the Market Monitor will contact the Market Participant for that information. The Market Monitor may communicate with the counterparty to confirm the firm purchase or sale and will include the transacted MWs to calculate net resource capacity for both purchaser and seller. If one of the parties disputes the firm purchase or sale to the Market Monitor, then the firm purchase or sale will not be used in the calculation of either the purchaser’s or seller’s net resource capacity subject to any dispute resolution.

B. A Market Participant’s compliance with the must offer obligation for an Asset Owner is as follows:
(1) A Market Participant that has offered all of its available Resources for an Asset Owner, with a commitment status described in Sections 4.1(10)(a), 4.1(10)(b), and/or 4.1(10)(c) of this Attachment AE, for an hour of the Operating Day is deemed to be in compliance with the must offer requirement for that Asset Owner for that hour regardless of its maximum hourly Reported Load and/or, Operating Reserve obligation.

(2) A Market Participant that does not meet the condition described in Section 2.11.1(B)(1) of this Attachment AE for an Asset Owner for an hour of the Operating Day, but has net resource capacity for that Asset Owner for that hour greater than or equal to 90% of its load for that Asset Owner as described in Section 2.11.1(A)(1) of this Attachment AE is deemed to be in compliance for that Asset Owner with the must offer requirement for that hour.

(3) To the extent that a Market Participant does not meet the conditions described in either Section 2.11.1(B)(1) or (2) of this Attachment AE for an Asset Owner, the Market Participant shall be deemed noncompliant with the must offer requirement for that Asset Owner for that hour and will be assessed a penalty for that hour as determined in Section 3.9 of Attachment AF of this Tariff.

C. Market Monitor shall monitor a Market Participant’s Load, Operating Reserve obligation, offered Resources and net resource capacity, for an Asset Owner for each hour of the Operating Day to determine whether the Market Participant has complied with the must offer obligation set forth in Section 2.11.1(B) of this Attachment AE.
2.17 Electric Storage Resource

ESRs may register as any valid Resource type and are subject to the same service provision rules as any other Resource within that type.

(1) If not registered as an MSR the energy withdrawal from the Transmission System must be included in a Load Settlement Location and are subject to the same rules as other Load.

(2) If an ESR is registered as an MSR, the following applies:
   a) MSRs may provide Energy, Regulation-Up, Regulation-Down, Spinning Reserve, Supplemental Reserve, and Uncertainty Reserve services upon meeting the technical and applicable requirements for these services in this Attachment AE and the Market Protocols.
   b) MSRs must provide Offer parameters as prescribed in Section 4.1 of this Attachment AE.
   c) MSR Offer Curves may include negative MW values to account for the entire dispatchable range of the MSR.
   d) As with other Resources, the metering requirements for MSRs include real-time and settlement quality metering. For MSRs that are not directly connected to the Transmission System, metering may include facilities used by the distribution company.
   e) Self-Charging MSRs or MSRs charging beyond the instructed amount are subject to all applicable transmission charges under the Tariff.
   f) Market Participants registering an MSR must also request transmission service under Part II or Part III of this Tariff.
      i. In the absence of explicit transmission service reservation arrangements by the Market Participant for the uninstructed energy withdrawals, the Market Participant will be billed the unreserved use rate as defined in Section 13.7 (c) or 14.5 of this Tariff.
      ii. Dispatch Instruction by the Transmission Provider for the MSR to provide Energy, Regulation-Up, Regulation-Down, Spinning Reserve, or
Supplemental Reserve that incidentally results in charging activity shall not be subject to a bill for transmission service during those actions.

g) The Real-Time Energy consumption is settled at the LMP as per Section 8.3 of this Attachment AE.
   
i. In the event that the MSR is not directly connected to the Transmission System and the distribution company is unable or unwilling to separate the charging activity from other retail service, the MSR will not be subject to settlement by the Transmission Provider for either the transmission charge or the energy consumption.

h) MSRs are not considered continuously dispatchable in a given interval if a directional commitment limitation exists for that interval. A directional commitment limitation occurs when the Minimum Charge Time is not equal to zero, Minimum Discharge Time is not equal to zero, Minimum Charge Limit is not equal to zero, or Minimum Discharge Limit is not equal to zero. If such a limitation exists, the MSR may offer either charge or discharge capacity in a given interval but not both. MSRs that do not have a directional commitment limitation are considered continuously dispatchable and will be evaluated for commitment and dispatch from the Maximum Charge Limit to the Maximum Discharge Limit.
3.1.4 Operating Reserve and Instantaneous Load Capacity Requirements

The Transmission Provider shall calculate the amount of Operating Reserves required for the Operating Day, on both a system-wide and Reserve Zone basis, in order to comply with the reliability requirements specified in the SPP Criteria. In addition, the Transmission Provider shall calculate the amount of Instantaneous Load Capacity required for the Operating Day on a system-wide basis in order to ensure that load can be reliably serviced in real-time. The Transmission Provider shall, on a daily basis:

1. Calculate the hourly Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, Ramp Capability Down, and Uncertainty Reserve requirements on an SPP Balancing Authority Area basis and post such results by 0600 hours Day-Ahead for use in the Day-Ahead Market, Day-Ahead RUC, Intra-Day RUC and RTBM;

2. Calculate the total minimum and total maximum Operating Reserve requirement for Operating Reserve deployment in the up direction and for deployment of Operating Reserve in the down direction for each Reserve Zone. These minimum and maximum Operating Reserve requirements will be determined by conducting a simulated energy transfer study for each hour of the Operating Day on the transmission system, reflecting expected outages and economic energy flows, in order to determine the energy transfer limitations into or out of a Reserve Zone in any hour. If a Reserve Zone is unable to import enough Energy after a contingency and still maintain all necessary operating limits, a minimum amount of Operating Reserve may be required to be carried in that Zone. The minimum Operating Reserve requirement is the largest difference between the Resource MW lost in the simulated contingency and the resulting import capability of that Reserve Zone. Similarly, if a Reserve Zone is unable to export additional Energy after a contingency outside of that Reserve Zone, then a maximum amount of Operating Reserve that is deliverable from that Zone will be specified in order to ensure that deliverable reserves are carried in other Zones. The maximum Operating Reserve limitation is equal to the export capability of that Reserve Zone when replacing Energy lost due to a Resource contingency outside of that Reserve Zone. The Transmission Provider may, at its option, set specific
Regulation-Up and/or Spinning Reserve minimum requirements for each Reserve Zone, as needed, to address reliability issues that can only be alleviated through carrying synchronized reserves. In such cases, the Transmission Provider will include these minimum Regulation-Up and/or Spinning Reserve requirements when posting the Operating Reserve requirements by 0600 Day-Ahead;

(3) Estimate each Market Participant’s Operating Reserve obligation by Asset Owner in each Reserve Zone and provide such information to Market Participants by 0600 hours Day-Ahead. The Transmission Provider shall calculate such estimates by multiplying the system-wide Operating Reserve requirements calculated in (1) above by the Transmission Provider’s estimate of each Asset Owner’s load in each Reserve Zone divided by the Transmission Provider’s estimate of system-wide load;

(4) The Transmission Provider may increase Operating Reserve requirements for the Day-Ahead RUC, Intra-Day RUC and RTBM above the requirements used in the Day-Ahead Market, including changes to Reserve Zone minimums and maximums, as required to meet increases in reliability requirements caused by changes in system conditions; and

(5) Calculate the hourly Instantaneous Load Capacity requirements for an interval on an SPP Balancing Authority Area basis for use in the Day-Ahead Market, Day-Ahead RUC and Intra-Day RUC in accordance with the calculation procedures specified in the Market Protocols.
3.1.7 Product Substitution

To ensure rational pricing of cleared Operating Reserve products, the SCED algorithm will include product substitution logic as follows:

A. Any Regulation-Up Offers may be used to meet Contingency Reserve requirements if Regulation-Up Offer is more economic or is required to meet the overall Contingency Reserve requirement;

B. Any Spinning Reserve Offers may be used to meet Supplemental Reserve requirements if the Spinning Reserve Offer is more economic or is required to meet the overall Operating Reserve requirement;

C. The product substitution logic ensures that the MCP for Regulation-Up Service is always greater than or equal to the Spinning Reserve MCP and that the Spinning Reserve MCP is always greater than or equal to the Supplemental Reserve MCP.

D. Ramp Capability Up and Ramp Capability Down products are not eligible for product substitution with other Operating Reserves.

E. Uncertainty Reserve is not eligible for product substitution with other Operating Reserves.
3.5 Integrated Marketplace Pricing

The Transmission Provider shall calculate Day-Ahead Market and RTBM LMPs for Energy at each Settlement Location.


The Transmission Provider shall calculate annual and monthly Auction Clearing Prices (“ACPs”) at each Settlement Location.
4.1 Offer Submittal

Beginning seven (7) days prior to the Operating Day, Market Participants may begin to submit Offers for use in the Day-Ahead Market and Offers for use in the RTBM. Day-Ahead Market Offers may be updated up to the close of the Day-Ahead Market and RTBM Offers may be updated thirty (30) minutes prior to each Operating Hour. Offer submittals shall conform to the following:

(1) Offers submitted in the Day-Ahead Market are independent from Offers submitted in the RTBM except that, if Regulation-Up Service and/or Regulation-Down Service is cleared in the Day-Ahead Market, Regulation-Up Mileage Offers and/or Regulation-Down Mileage Offers for the associated Resources for use in the RTBM are set equal to the Regulation-Up Mileage Offers and/or Regulation-Down Mileage Offers for the associated Resources submitted for use in the Day-Ahead Market;

(2) Market Participants may specify that the Offers submitted in the Day-Ahead Market also apply in the RTBM;

   (a) Such an Offer shall be rejected in the RTBM if the Market Participant has submitted a Resource commitment status of “not participating” as described in Section 4.1(10)(e) of this Attachment AE and the Resource is not participating in the Day-Ahead Market.

(3) Submitted Resource Offers will automatically roll forward hour to hour within each respective market only when no Resource Offer has been submitted for that interval;

(4) Offers may be submitted that vary for each hour of the Operating Day, except the Offer parameters related to unit commitment as defined in the Market Protocols for which a single value is submitted. These unit commitment Offer parameters will automatically roll forward in each hour of the subsequent Operating Day only when no unit commitment Offer parameters have been submitted for that Operating Day;

(5) Offers submitted for use in the RTBM are also used in the RUC;
(6) Resource Offers may only be submitted at Resource Settlement Locations, Import Interchange Transaction Offers may only be submitted at External Interface Settlement Locations and Virtual Energy Offers may be submitted at any Settlement Location;

(7) For Regulation Qualified Resources and Regulation-Up Qualified Resources, Market Participants may submit Regulation-Up Offers, Regulation-Up Mileage Offers, Spinning Reserve Offers and Supplemental Reserve Offers provided that if the Regulation-Up Offer is negative, the Regulation-Up Mileage Offer must equal zero. For Regulation-Down Qualified Resources and Regulation Qualified Resources, Market Participants may submit Regulation-Down Offers and Regulation-Down Mileage Offers provided that if the Regulation-Down Offer is negative, the Regulation-Down Mileage Offer must equal zero. For Spin Qualified Resources, Market Participants may submit Resource Offers for Spinning Reserve and Supplemental Reserve. For Supplemental Qualified Resources, Market Participants may submit Resource Offers for Supplemental Reserve. If a Spinning Reserve Offer is submitted for a Resource, and a Resource Offer for Supplemental Reserve is not submitted, then the Supplemental Reserve Offer is set equal to zero. Resource qualifications are verified by the Transmission Provider as part of the registration process as follows:

(a) A Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource must pass a specific regulation test as defined in Section 2.10.3 of this Attachment AE and must be capable of deploying one hundred percent (100%) of cleared Regulation-Up and/or Regulation-Down within the Regulation Response Time for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(b) A Spin Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Spinning Reserve and/or cleared Supplemental Reserve within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and
provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(c) Supplemental Qualified Resource:

(i) A Supplemental Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Supplemental Reserve from an off-line state within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(ii) Alternatively, an MCR may also become a Supplemental Qualified Resource by self-certifying that the MCR is capable of deploying 100% of cleared Supplemental Reserve through a transition to a higher capacity configuration within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(d) An Uncertainty Reserve Qualified Resource must self-certify that the Resource is capable of following RTBM Dispatch Instruction and has the ability to increase and maintain its output for at least the duration of the Uncertainty Reserve response time (once the specified resource output is achieved).

(8) Resource Offers are limited by the Offer caps and floors specified in Section 4.1.1 of this Attachment AE;

(9) The Resource Offer parameters that constitute a valid Offer for use in either the Day-Ahead Market or RTBM are submitted using the data formats, procedures, and information defined in the Market Protocols and will include the following (as further defined in the Market Protocols):

- Resource Name
- Resource Type
- Start-up Offer
- No-Load Offer
- Energy Offer Curve
- Transition State Offer (for an MCR)
- Transition State Time (for an MCR)
- Regulation–Up and Regulation-Down Offers
- Regulation-Up Mileage and Regulation-Down Mileage Offers
- Spinning and Supplemental Reserve Offers
- Uncertainty Reserve Offers
- Sync-To-Min and Min-To-Off Times
- Start-Up Time
- Hot to Intermediate and Hot to Cold Times (not applicable to an MSR)
- Maximum Daily and Weekly Starts
- Maximum Daily Energy
- Maximum and Minimum Run Times
- Plant Minimum Down Time (for an MCR)
- Plant Minimum Run Time (for an MCR)
- Group Minimum Down Time (for an MCR)
- Group Minimum Run Time (for an MCR)
- Minimum Down Time
- Minimum Emergency Capacity Operating Limit and Run Time (not applicable to an MSR)
- Minimum Normal, Economic, and Regulation Capacity Operating Limits (not applicable to an MSR)
- Maximum Normal, Economic, and Regulation Capacity Operating Limits (not applicable to an MSR)
- Maximum Emergency Capacity Operating Limits and Run Time (not applicable to an MSR)
- Maximum Off-line Supplemental Reserve Response Limit
- Maximum Transition State Supplemental Reserve Resource Response Limit (for an MCR)
- Ramp-Rate-Up and Ramp-Rate-Down
- Turn-Around Ramp Rate Factor
- Regulation Ramp Rate
- Contingency Reserve Ramp Rate
- Resource Status
- Interest Percent Share
- State of Charge Forecast (MSR only)
- Maximum and Minimum State of Charge (MSR only)
- Maximum and Minimum Charge Limit (MSR only)
- Maximum and Minimum Discharge Limit (MSR only)
- Maximum and Minimum Charge Time (MSR only)
- Maximum and Minimum Discharge Time (MSR only)
- ESR Loss Factor (MSR only)
- Maximum and Minimum Emergency Charge Limit (MSR only)
- Maximum and Minimum Emergency Discharge Limit (MSR only)

(10) Market Participants must specify a Resource commitment status as part of the Resource Offer using the data formats, procedures, and information defined in the Market Protocols. Market Participants use the commitment status to indicate:

(a) Whether they are self-committing a Resource;
(b) Whether the Resource may be committed by the Transmission Provider;
(c) Whether the Resource may be committed by the Transmission Provider only to alleviate an anticipated Emergency Condition or local reliability issue;
(d) Whether the Resource is on an outage; or
(e) Whether the Resource is not participating in the Day-Ahead Market.

(11) Market Participants must specify a Resource dispatch status as part of the Resource Offer using the data formats, procedures and information defined in the Market Protocols. Market Participants use the dispatch status to notify the Transmission Provider whether the Resource is:

(a) Eligible for Energy Dispatch;
(b) Eligible for Operating Reserve clearing; or
(c) Self-scheduled for Operating Reserve.
If the dispatch status for a Resource does not indicate it is eligible for Energy Dispatch, then such Resource shall not be subject to charges and credits calculated under Section 8.6.15 of this Attachment AE and shall not be subject to the deviation calculations under Sections 8.6.7(A)(2)(e) and 8.6.7(A)(2)(g) of this Attachment AE.

(12) Resource limits submitted as part of the Resource Offer must pass the validation rules defined in the Market Protocols, otherwise, the Resource Offer will be rejected; and

(13) The Market Participant must comply with the must-offer requirements as defined in Section 2.11 of this Attachment AE.
4.1.1 Offer Caps and Floors

Submission of Energy Offer Curves, Start-Up Offers, No-Load Offers, and Operating Reserve Offers by Market Participants for use in the Day-Ahead Market and the RTBM shall be limited by the following Offer caps and floors:

1. Safety-net Energy Offer cap = $1,000/MWh; Energy Offers greater than $1,000/MWh are subject to Section 3.2(F) of Attachment AF of this Tariff.
2. Virtual Energy Offer Cap = $2,000/MWh;
3. Import/Export Transaction Offer Cap = $2,000/MWh;
4. Regulation-Up Service Offer cap = $500/MW;
5. Regulation-Down Service Offer cap = $500/MW;
6. Contingency Reserve Offer cap = $100/MW;
7. Energy Offer floor = Negative $500/MWh;
8. Regulation Service Offer floor = Negative $500/MW;
9. Regulation-Up Mileage Offer floor = $0/MW;
10. Regulation-Down Mileage Offer floor = $0/MW;
11. Contingency Reserve Offer floor = Negative $100/MW;
12. Start-Up Offer floor = $0;
13. No-Load Offer floor = $0;
14. Uncertainty Reserve Offer cap = $1000/MW;
15. Uncertainty Reserve Offer floor = $0/MW.

In addition to these Offer caps and floors, submission of Offers may be limited by the requirements of Attachment AF of this Tariff.
5.1.3 Day-Ahead Market Results

The Transmission Provider will notify each Market Participant of the Day-Ahead Market results for each hour of the Operating Day.

A. The following results are communicated to each Market Participant for only its specific Resources, no later than the posting of the Day-Ahead Market:


   (a) Cleared Offers for Energy associated with Resource Offers represent a physical Resource commitment.

   (b) Resources committed by the Transmission Provider in the Day-Ahead Market that incur one or more start-up costs within the Operating Day as a result of the Transmission Provider Day-Ahead Market commitment are guaranteed to receive revenues that are at least equal to the Resource Offer costs for the cleared amount of Energy, Regulation-Up Service, Regulation-Down Service, Spinning Reserve or Supplemental Reserve for that Resource.

   (c) Cleared Regulation-Up Service MWs represent only those MWs cleared to meet the Regulation-Up Service requirement.

   (d) Cleared Regulation-Down Service MWs represent only those MWs cleared to meet the Regulation-Down Service requirement.

   (e) Cleared Spinning Reserve MWs represent the Spinning Reserve MWs cleared to meet the Spinning Reserve requirement and Regulation-Up Service MWs cleared to meet the Spinning Reserve requirement through product substitution as described under Section 3.1.7 of this Attachment AE.

   (f) Cleared Supplemental Reserve MWs represent the sum of Supplemental Reserve MWs cleared to meet the Supplemental Reserve requirement and Regulation-Up Service MWs and Spinning Reserve MWs cleared to meet the Supplemental Reserve requirement through product substitution as described under Section 3.1.7 of this Attachment AE.
(g) Cleared Ramp Capability Up MWs represent only those MWs cleared to meet the Ramp Capability Up requirement.

(h) Cleared Ramp Capability Down MWs represent only those MWs cleared to meet the Ramp Capability Down requirement.

(i) Cleared Uncertainty Reserve MWs represent only those MWs cleared to meet the Uncertainty Reserve requirement.

(2) Cleared Virtual Energy Offers;
(3) Cleared Import Interchange Transaction Offers;
(4) Cleared Demand Bids;
(5) Cleared Virtual Energy Bids;
(6) Cleared Export Interchange Transaction Bids; and
(7) Cleared Through Interchange Transactions.

B. The following pricing solution results are communicated to all Market Participants after the posting of the dispatch solution results:

(1) LMPs for each Settlement Location, the marginal Energy component (“MEC”) of the LMP, the Marginal Congestion Component (“MCC”) of the LMP and the Marginal Loss Component (“MLC”) of the LMP for each Settlement Location; and

(2) MCPs for Regulation-Up Service, Regulation-Down Service, Spinning Reserve and Supplemental Reserve for each Reserve Zone.
6.2.2 Real-Time Balancing Market Execution

The Transmission Provider will attempt to execute the RTBM every five (5) minutes for the next Dispatch Interval based on the inputs described above. In the event the Transmission Provider is unable to execute the RTBM or to approve a valid solution for the RTBM, the clearing from the last approved RTBM will carry forward until the approval of a new RTBM.

(1) A simultaneous co-optimization methodology utilizing a SCED algorithm is employed to calculate Resource Dispatch Instructions and clear Regulation-Up Service, Regulation Down Service, Spinning Reserve, Supplemental Reserve, Ramp Capability Up, Ramp Capability Down, and Uncertainty Reserve to meet the Transmission Provider load forecast and Operating Reserve requirements at minimum costs based upon submitted Offers while respecting Resource operating constraints and transmission constraints as described in Section 3.3.1 of this Attachment AE.

(2) The SCED algorithm includes marginal loss sensitivity factors that approximate the change in marginal system losses for a change in Energy dispatch.

(3) In certain situations, enforcing constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, the Transmission Provider must apply VRLs in SCED.

(4) The co-optimization logic will provide through the Shadow Price calculation, MCPs for Operating Reserve that include lost opportunity costs incurred as a result of Operating Reserve clearing.

(5) Additionally, the Transmission Provider will execute a look-ahead SCED prior to the RTBM SCED process. The Transmission Provider will use the look-ahead SCED results to: (1) anticipate the need to adjust Dispatch Instructions for the current Dispatch Interval to prepare to meet forecasted changes in the load several Dispatch Intervals into the future and (2) determine commitment of Resources that can be on-line within the Operating Hour including Fast Start Resources.

6.2.2.1 Emergency Operations – Capacity Shortage
(1) In addition to the incorporation of the capacity up to Resources’ Maximum Emergency Capacity Operating Limits prior to the Operating Hour as described under Sections 5.1.2(1)(a)(i) and 5.2.2(2)(a) of this Attachment AE, the Transmission Provider may incorporate any remaining emergency capacity limits as needed during the Operating Hour. The Transmission Provider shall continue implementation of emergency procedures which may have been implemented prior to the Operating Hour or shall begin implementation of emergency procedures within the Operating Hour, as needed, in accordance with its authority as Reliability Coordinator.

(a) If there is an actual Operating Reserve shortage during a Dispatch Interval, either on a system-wide or a Reserve Zone basis, the system-wide or Reserve Zone Scarcity Prices will be implemented as specified in Sections 8.3.1 and 8.3.4.2 of this Attachment AE.

(b) If there is a shortage of available capacity to meet Energy requirements on a system-wide, LMPs will be set through Scarcity Pricing procedures as specified in Section 8.3.1 of this Attachment AE.

6.2.2.2 Emergency Operations – Excess Generation

(1) The Transmission Provider will take any or all of the following actions, as time permits, within the Operating Hour to address excess generation conditions on either a system-wide or Reserve Zone basis:

(a) Notify any remaining Resources not cleared for Regulation-Down Service and not notified prior to the Operating Hour that they will be dispatched down to their Minimum Emergency Capacity Operating Limits, Minimum Emergency Discharge Limits, or Maximum Emergency Charge Limits;

(b) De-commit any remaining Resources that were self-committed following the Day-Ahead RUC;

(c) Pro-rata curtail, on a MW basis, any remaining fixed non-firm Import Interchange Transactions;

(d) Pro-rata curtail, on a per MW basis, any fixed firm Import Interchange Transactions;
(e) Reduce Resources with cleared Regulation-Down Service economically, as needed, down to Minimum Emergency Capacity Operating Limits, Minimum Emergency Discharge Limits, or Maximum Emergency Charge Limits;

(f) Coordinate with generation Operators, SPP Balancing Authority Operator and SPP Reliability Coordinator to de-commit generation to meet power balance; and

(g) Commit any MSR that is available for charging.

(2) If actions taken under (1) above are not sufficient to relieve the excess generation condition in any Dispatch Interval either on a system-wide or Reserve Zone basis, LMPs will be set to the lesser of zero (0) or the Offer prices associated with Energy down to the minimum emergency limit, to the extent that the Regulation-Down requirement can be maintained. If the actions under (1) above create a Regulation-Down Service shortage during any Dispatch Interval either on a system-wide or Reserve Zone basis, the MCPs for Regulation-Down Service will reflect Scarcity Prices and LMPs will reflect negative Scarcity Prices.

(3) In parallel with the actions under (1) above, if there is a transmission constraint within a Reserve Zone occurring simultaneously with a Reserve Zone excess capacity event, the Transmission Provider may take any or all of the following additional actions:

(a) Identify and communicate with the Market Participant concerning Resources with greater than a five percent (5%) generation shift factor on the constraint and fixed Import Interchange Transactions with greater than a three percent (3%) transfer distribution factor on constraint;

(b) Issue Transmission Loading Relief (“TLR”) provisions, in accordance with Attachment R, to curtail any Interchange Transactions that may be contributing to the loading;

(c) Commit Resources in the constrained area if they can be re-dispatched with other Resources in the constrained area to relieve constraint without contributing to the excess capacity situation.
6.2.2.3 Congestion Management

The Transmission Provider shall use the following process to coordinate the operations of the RTBM to manage congestion within the SPP Balancing Authority Area and between the SPP Balancing Authority Area and external Balancing Authority Areas:

(a) The Transmission Provider shall submit the Market Flow impact on each Coordinated Flowgate and Reciprocal Coordinated Flowgate to the IDC.

(b) The Transmission Provider shall assign curtailment priorities to the Market Flow on each flowgate in the following priority categories:

(i) Curtailment priorities for flowgates that have not been defined as a Coordinated Flowgate or a Reciprocal Coordinated Flowgate shall be assigned in accordance with NERC TLR procedures.

(ii) For Coordinated Flowgates, the Transmission Provider will assign Market Flow in the firm priority up to the firm limit with any excess Market Flow assigned as non-firm network.

(iii) For Reciprocal Coordinated Flowgates, the Transmission Provider will divide its Market Flows into firm, non-firm network, and non-firm hourly curtailment priorities. The Transmission Provider will first assign Market Flow in the firm priority up to the firm limit, then assign remaining Market Flow in the non-firm network priority up to the non-firm network limit, and finally assign any excess Market Flow as non-firm hourly.

(c) The Market Flow associated with operation of the RTBM shall be determined by the Transmission Provider. For Coordinated Flowgates, any Market Flow from RTBM operation in excess of that assigned to the firm priority shall be assigned a non-firm priority. For Reciprocal Coordinated Flowgates, any Market Flow from RTBM operation in excess of amounts assigned to firm or non-firm network priorities shall be assigned a non-firm hourly priority.

(d) When congestion occurs on a flowgate that requires a TLR event, the IDC will identify the amount of relief required from Market Flows on the Coordinated Flowgate or Reciprocal Coordinated Flowgate.
(e) When congestion occurs on a flowgate that does not require a TLR event, the Transmission Provider shall manage such congestion using its security constrained dispatch software until the flowgate loading is within its applicable operating limits.

(f) The Transmission Provider shall achieve the required reduction in Market Flows provided by the IDC using its security constrained dispatch software in the following order until the desired reduction in Market Flows is achieved:

   (i) To the extent that Market Flows are contributing to the constrained condition, the Transmission Provider shall restrict the ability of the market operating system from contributing further to the constrained condition by binding the Coordinated Flowgate or Reciprocal Coordinated Flowgate constraint. The security constrained dispatch of Dispatchable Resources shall continue within each priority level until the Market Flows within that priority level have been reduced to zero or the flowgate constraint is eliminated, whichever comes first.
Following execution of the RTBM SCED, the Transmission Provider shall communicate the results to Market Participants.

(1) The following results are communicated to each Market Participant for only its specific Resources prior to the start of the applicable Dispatch Interval:

(a) Resource Dispatch Instructions. The Dispatch Instruction is a MW output target for the end of the applicable Dispatch Interval.


(i) Cleared Regulation-Up Service MWs represent only those MWs cleared to meet the Regulation-Up Service requirement.

(ii) Cleared Regulation-Down Service MWs represent only those MWs cleared to meet the Regulation-Down Service requirement.

(iii) Cleared Spinning Reserve MWs represent the Spinning Reserve MWs cleared to meet the Spinning Reserve requirement and Regulation-Up Service MWs cleared to meet the Spinning Reserve requirement through product substitution as described under Section 3.1.7 of this Attachment AE.

(iv) Cleared Supplemental Reserve MWs represent the sum of Supplemental Reserve MWs cleared to meet the Supplemental Reserve requirement and Regulation-Up Service MWs and Spinning Reserve MWs cleared to meet the Supplemental Reserve requirement through product substitution as described under Section 3.1.7 of this Attachment AE.

(v) Cleared Ramp Capability Up MWs represent only those MWs cleared to meet the Ramp Capability Up requirement.

(vi) Cleared Ramp Capability Down MWs represent only those MWs cleared to meet the Ramp Capability Down requirement.

(vii) Cleared Uncertainty Reserve MWs represent only those MWs cleared to meet the Uncertainty Reserve requirement.
(2) The following pricing solution results are communicated to all Market Participants after the posting of the dispatch solution and are used for settlement purposes;

(a) LMPs for each Settlement Location, the MCC of LMP for each Settlement Location and the MLC of LMP for each Settlement Location.

(b) MCPs for Regulation-Up Service, Expected Regulation-Up Mileage, Regulation-Down Service, Expected Regulation-Down Mileage, Spinning Reserve and Supplemental Reserve for each Reserve Zone.
8.3.4 Market Clearing Price Calculations

The MCP represents the cost of supplying an increment of Operating Reserve, taking into account lost opportunity cost and is composed of the marginal Operating Reserve costs and marginal costs associated with Operating Reserve scarcity. The Day-Ahead Market and RTBM MCPs at a Reserve Zone for Resources with cleared Regulation-Up Service, Regulation-Down Service, Spinning Reserve and/or Supplemental Reserve in that Reserve Zone are equal to the summation of the applicable Shadow Prices associated with the constraints as described in subsections (1) and (2) below. Calculation of MCPs for Expected Regulation-Up Mileage and Expected Regulation-Down Mileage are calculated as described in subsections (3) and (4) below:

(1) There are seven sets of constraints which apply on both a system-wide basis and a Reserve Zone basis:
   (a) A Contingency Reserve plus Regulation-Up constraint is equal to the sum of the Contingency Reserve requirement and the Regulation-Up requirement;
   (b) A Regulation-Up plus Spinning Reserve constraint is equal to the sum of the Regulation-Up requirement and the Spinning Reserve requirement;
   (c) A Regulation-Up constraint is equal to the Regulation-Up requirement;
   (d) A Regulation-Down constraint is equal to the Regulation-Down requirement;
   (e) A Ramp Capability Down constraint is equal to the Ramp Capability Down requirement;
   (f) A Ramp Capability Up constraint is equal to the Ramp Capability Up requirement; and
   (g) An Uncertainty Reserve constraint is set equal to the Uncertainty Reserve requirement.

(2) Operating Reserve MCPs for each Reserve Zone are calculated as follows:
   (a) The Regulation-Up Service MCP is equal to sum of the Shadow Prices for the system-wide and zonal Regulation-Up constraints, system-wide and zonal Regulation-Up plus Spinning Reserve constraints and the system-wide and zonal Contingency Reserve plus Regulation-Up constraints;
(b) The Spinning Reserve MCP is equal to the sum of the Shadow Prices for the system-wide and zonal Regulation-Up plus Spinning Reserve constraints and the system-wide and zonal Contingency Reserve plus Regulation-Up constraints;

(c) The Supplemental Reserve MCP is equal to the sum of the Shadow Prices for the system-wide and zonal Contingency Reserve plus Regulation-Up constraints;

(d) The Regulation-Down MCP is equal to the Shadow Price for the system-wide and zonal Regulation-Down constraint;

(e) The Ramp Capability Down MCP is equal to the Shadow Price for the system-wide and zonal Ramp Capability Down constraint;

(f) The Ramp Capability Up MCP is equal to the Shadow Price for the system-wide and zonal Ramp Capability Up constraint; and

(g) The Uncertainty Reserve MCP is equal to the Shadow Price for the system-wide Uncertainty Reserve constraint.

(3) RTBM MCPs for Expected Regulation-Up Mileage are set equal to the highest Regulation-Up Mileage Offer of all Resources economically cleared to provide Regulation-Up Service in a particular Dispatch Interval. For Resources submitting a Regulation-Up Service dispatch status as described under Section 4.1(11)(c) of this Attachment AE, the cleared amount of Regulation-Up Service MW must be greater than the submitted self-schedule MW in order to be considered economically cleared;

(4) RTBM MCPs for Expected Regulation-Down Mileage are set equal to the highest Regulation-Down Mileage Offer of all Resources economically cleared to provide Regulation-Down Service in a particular Dispatch Interval. For Resources submitting a Regulation-Down Service dispatch status as described under Section 4.1(11)(c) of this Attachment AE, the cleared amount of Regulation-Down Service MW must be greater than the submitted self-schedule MW in order to be considered economically cleared;

(5) In the event a system-wide failure of the RTBM systems results in a loss of the ability to calculate MCPs, RTBM Operating Reserve will continue to be settled
financially under this Tariff based upon estimated MCPs. The Transmission Provider shall notify Market Participants if RTBM Operating Reserve is to be settled using estimated prices.

(a) If the failure of the RTBM systems occurs for twelve (12) Dispatch Intervals or less, the estimated MCPs shall be the most recently calculated MCPs for each affected Reserve Zone and shall be utilized for settlement purposes for each of the Dispatch Intervals in which MCP pricing data is missing.

(b) If the failure of the RTBM systems occurs for more than twelve (12) Dispatch Intervals, the Transmission Provider shall calculate MCPs using mitigated Offers for the RTBM in a manner that reflects, as closely as practicable, the MCPs that would have resulted but for the RTBM systems failure, and shall use such MCPs for settlement purposes for each of the Dispatch Intervals in which MCP pricing data is missing. To the extent that the Transmission Provider is unable to calculate RTBM MCPs, the Transmission Provider shall use the MCPs generated in the Day-Ahead Market for RTBM settlement.

(6) If for any reason a portion of generation and load within the SPP Balancing Authority Area becomes isolated from the rest of the SPP Balancing Authority Area (“Island”), RTBM MCPs will not be calculated and procurement of Operating Reserve within the Island will not be performed.
8.3.4.1 Impact of Violation Relaxation Limits on Security Constrained Economic Dispatch (MCP)

The applicable VRLs impact SCED in the following manner: VRLs are applied independently in the dispatch solution and pricing solution described in Section 3.3.1 of this Attachment AE.

1. When a Resource capacity, global power balance, Resource ramp, Spinning Reserve, or operating constraint is reached but not exceeded, it is referred to as “binding.” In this state, VRLs are not applicable and MCPs are calculated through the normal SCED solution; and

2. When a Resource capacity, global power balance, Resource ramp, Spinning Reserve, or operating constraint is exceeded and cannot be resolved, the applicable constraint is relaxed so that SCED can solve. The VRL values applied by SCED in this case act as a cap on the Shadow Price on the applicable Operating Constraint. MCPs are determined by the relaxed SCED solution.
8.3.4.2 Impact of Scarcity Pricing on Locational Marginal Prices and Market Clearing Prices

(1) Demand Curves are applied independently in the dispatch solution and pricing solution described in Section 3.3.1 of this Attachment AE. The Transmission Provider shall use Demand Curves to reflect Scarcity Prices in both the Day-Ahead Market and RTBM during times of Energy and/or Operating Reserve shortages, either on a system-wide and/or Reserve Zone basis.

(2) Scarcity Prices are reflected in MCPs using the following Demand Curves:

(a) The Contingency Reserve Demand Curve Price is applied on both a system-wide basis and zonal basis and is equal to the product of the applicable Contingency Reserve Scarcity Factor, defined in accordance with the Market Protocols, and the sum of the safety-net Energy Offer cap and the Contingency Reserve Offer cap as specified in Section 4.1.1 of this Attachment AE.

(b) The Regulation-Up Service Scarcity Pricing is determined in accordance with the following subparagraphs – 8.3.4.2(2)(b)(i) and (ii) – provided that maximum Regulation-Up Demand Curve Price is equal to the sum of the Regulation-Up Service Offer cap and the Contingency Reserve Offer cap as specified in Section 4.1.1 of this Attachment AE and is applied on a system-wide basis.

(i) If Regulation-Up shortages are caused by insufficient ramping capabilities, then the Regulation-Up Demand Curve Price is equal to the product of the applicable Regulation-Up Scarcity Factor and the Regulation Base Demand Price.

(ii) If Regulation-Up shortages are the result of insufficient capacity, then the Regulation-Up Demand Curve Price is equal to the greater of (a) the marginal Resource clearing cost or (b) the product of the applicable Regulation-Up Scarcity Factor and the Regulation Base Demand Price.

(c) The Regulation-Down Service Scarcity Pricing is determined in accordance with the following subparagraphs – 8.3.4.2(2)(c)(i) and (ii) – provided that maximum Regulation-Down Demand Curve Price is equal
to the sum of the Regulation-Down Service Offer cap and the Contingency Reserve Offer cap as specified in Section 4.1.1 of this Attachment AE and is applied on a system-wide basis.

(i) If Regulation-Down shortages are caused by insufficient ramping capabilities, then the Regulation-Down Demand Curve Price is equal to the product of the applicable Regulation-Down Scarcity Factor and the Regulation Base Demand Price.

(ii) If Regulation-Down shortages are the result of insufficient capacity, then the Regulation-Down Demand Curve Price is equal to the greater of (a) the marginal Resource clearing cost and (b) the product of the applicable Regulation-Down Scarcity Factor and the Regulation Base Demand Price.

(d) Ramp Capability Up – The Transmission Provider calculates and posts Ramp Capability Up Scarcity Pricing in accordance with the following rules:

(i) The maximum Scarcity Price is calculated as the average cost per MW for all eligible Resources to recover their qualified cold Start-Up Offer, No-Load Offer, and Energy at minimum cost at their Maximum Normal Operating Limit. Eligible Resources are Resources which offer a cold start-up time of 10 minutes or less, a Minimum Run Time of 60 minutes or less, and are not on outage. The maximum Scarcity Price is equal to the cold Start-Up Offer plus the product of the Minimum Run Time and the No-Load Offer plus the Energy at minimum cost all divided by the Resource’s Maximum Normal Capacity Operating Limit or Maximum Discharge Limit as applicable.

(ii) The maximum Scarcity Price will be calculated each month using the previous three months offer data.

(iii) The Demand Curve levels for Ramp Capability Up will be equal to:

1. Shortages up to or equal to 5% of the requirement will equal, to the nearest dollar, 1/6 of the maximum Scarcity Price.
2. Shortages greater than 5% but less than or equal to 10% of the requirement will equal, to the nearest dollar, 1/3 of the maximum Scarcity Price.

3. Shortages greater than 10% but less than or equal to 15% of the requirement will equal, to the nearest dollar, 1/2 of the maximum Scarcity Price.

4. Shortages greater than 15% but less than or equal to 25% of the requirement will equal, to the nearest dollar, 2/3 of the maximum Scarcity Price.

5. Shortages greater than 25% but less than or equal to 40% of the requirement will equal, to the nearest dollar, 5/6 of the maximum Scarcity Price.

6. Shortages greater than 40% of the requirement will equal, to the nearest dollar, the maximum Scarcity Price.

(iv) The minimum amount for the Ramp Capability Up Demand Curve prices will be limited to $10.

(e) Ramp Capability Down – The Transmission Provider calculates and posts Ramp Capability Down Scarcity Pricing in accordance with the following rules:

(i) The maximum Scarcity Price is calculated as the average cost per MW for all eligible Resources to recover their qualified cold Start-Up Offer, No-Load Offer, and Energy at minimum cost at their Maximum Normal Operating Limit. Eligible Resources are Resources which offer a cold Start-Up Time of 10 minutes or less, a Minimum Run Time of 60 minutes or less, and are not on outage. The maximum Scarcity Price is equal to the cold Start-Up Offer plus the product of the Minimum Run Time and the No-Load Offer plus the Energy at minimum cost all divided by the Resource’s Maximum Normal Capacity Operating Limit or Maximum Discharge Limit as applicable.

(ii) The maximum Scarcity Price will be calculated each month using the previous three months offer data.

(iii) The Demand Curve levels for Ramp Capability Down will be equal to:
1. Shortages up to or equal to 5% of the requirement will equal, to the nearest dollar, 1/6 of the maximum Scarcity Price.

2. Shortages greater than 5% but less than or equal to 10% of the requirement will equal, to the nearest dollar, 1/3 of the maximum Scarcity Price.

3. Shortages greater than 10% but less than or equal to 15% of the requirement will equal, to the nearest dollar, 1/2 of the maximum Scarcity Price.

4. Shortages greater than 15% but less than or equal to 25% of the requirement will equal, to the nearest dollar, 2/3 of the maximum Scarcity Price.

5. Shortages greater than 25% but less than or equal to 40% of the requirement will equal, to the nearest dollar, 5/6 of the maximum Scarcity Price.

6. Shortages greater than 40% of the requirement will equal, to the nearest dollar, the maximum Scarcity Price.

(iv) The minimum amount for the Ramp Capability Down Demand Curve prices will be limited to $0.

(f) Uncertainty Reserve – The Transmission Provider calculates and posts Uncertainty Reserve Scarcity Pricing in accordance with the following rules:

1. The Uncertainty Reserve Demand Curve prices are determined by applying a factor to the Regulation Base Demand Price such that the magnitude of the Uncertainty Reserve Demand Curve price is less than the Regulation Base Demand Price.

2. The Demand Curve levels for Uncertainty Reserve will be equal to:
   a. Shortages up to or equal to 5% of the requirement will equal, to the nearest dollar, 0.05 times the Regulation Base Demand Price.
   b. Shortages greater than 5% but less than or equal to 10% of the requirement will equal, to the nearest dollar, 0.35 times the Regulation Base Demand Price.
c. Shortages greater than 10% but less than or equal to 15% of the requirement will equal, to the nearest dollar, 0.55 times the Regulation Demand Price.

d. Shortages greater than 15% but less than or equal to 20% of the requirement will equal, to the nearest dollar, 0.70 times the Regulation Demand Price.

e. Shortages greater than 20% of the requirement will equal, to the nearest dollar, 0.95 times the Regulation Demand Price.

3. The minimum amount for the Uncertainty Demand Curve prices will be limited to $10.

(3) Scarcity Prices will be reflected in LMPs when serving an incremental MW of energy worsens the Operating Reserve capacity shortage condition.

(4) During Operating Reserve shortage conditions on a system wide basis and/or zonal basis, Market Clearing Prices are impacted by Demand Curves as follows:

(a) If there is a system-wide shortage of Contingency Reserve, no shortage of Regulation-Up or Regulation-Down, and all zonal minimum requirements have been met:

(i) the system-wide Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(ii) the zonal Regulation-Up plus Contingency Reserve constraint Shadow Price is calculated normally and does not reflect the Contingency Reserve Demand Curve Price;

(iii) the Regulation-Up and Regulation-Down constraint Shadow Prices are calculated normally and do not reflect the Regulation-Up or Regulation-Down Demand Curve Prices;

(iv) the Supplemental Reserve MCP shall reflect the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE; and

(v) the Spinning Reserve MCP and the Regulation-Up MCP shall also reflect the Contingency Reserve Demand Curve Price through the
calculations described under Sections 8.3.4(2)(b) and 8.3.4(2)(a) of this Attachment AE respectively.

(b) If there is a system-wide shortage of Contingency Reserve, a shortage of Regulation-Up, no shortage of Regulation-Down, and all zonal minimum requirements have been met:

(i) the system-wide Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(ii) the system-wide Regulation-Up constraint Shadow Price is set equal to the Regulation-Up Demand Curve Price;

(iii) the zonal Regulation-Up plus Contingency Reserve constraint Shadow Price is calculated normally and does not reflect the Contingency Reserve Demand Curve Price;

(iv) the Regulation-Down constraint Shadow Price is calculated normally and does not reflect the Regulation-Down Demand Curve Price;

(v) the Supplemental Reserve MCP shall reflect the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(vi) the Spinning Reserve MCP shall also reflect the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(b) of this Attachment AE; and

(vii) the Regulation-Up MCP shall reflect the summation of the Contingency Reserve Demand Curve Price and the Regulation-Up Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE.

(c) If there is a system-wide shortage of Contingency Reserve, no shortage of Regulation-Up or Regulation-Down, and zonal minimum requirements cannot not be met:
(i) the system-wide Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(ii) the zonal Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(iii) the Regulation-Up and Regulation-Down constraint Shadow Prices are calculated normally and do not reflect the Regulation-Up or Regulation-Down Demand Curve Prices;

(iv) the Supplemental Reserve MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(v) the Supplemental Reserve MCP in all Reserve Zones in which the minimum requirements have not been met shall reflect the summation of the system-wide Contingency Reserve Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(vi) the Spinning Reserve MCP and Regulation-Up MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the Contingency Reserve Demand Curve Price through the calculations described under Sections 8.3.4(2)(b) and 8.3.4(2)(a) of this Attachment AE respectively; and

(vii) the Spinning Reserve MCP and Regulation-Up MCPs in all Reserve Zones in which the minimum requirements have not been met shall reflect the summation of the system-wide Contingency Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculations described under Sections 8.3.4(2)(b) and 8.3.4(2)(a) of this Attachment AE, respectively.
(d) If there is a system-wide shortage of Contingency Reserve, a shortage of Regulation-Up, no shortage of Regulation-Down, and zonal minimum requirements cannot not be met:

(i) the system-wide Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(ii) the zonal Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(iii) the Regulation-Up constraint Shadow Price is set equal to the Regulation-Up Demand Curve Price;

(iv) the Regulation-Down constraint Shadow Price is calculated normally and does not reflect the Regulation-Down Demand Curve Price;

(v) the Supplemental Reserve MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the Contingency Reserve Demand Curve price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(vi) the Spinning Reserve MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the Contingency Reserve Demand Curve price through the calculations described under Section 8.3.4(2)(b) of this Attachment AE;

(vii) the Regulation-Up MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the summation of the Regulation-Up Demand Curve Price and the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE;

(viii) the Supplemental Reserve MCP in all Reserve Zones in which the minimum requirements have not been met shall reflect the summation of the system-wide Contingency Reserve Demand
Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(ix) the Spinning Reserve MCP in all Reserve Zones in which the minimum requirements have not been met shall reflect the summation of the system-wide Contingency Reserve Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(b) of this Attachment AE; and

(x) the Regulation-Up MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the summation of the Regulation-Up Demand Curve Price, the system-wide Contingency Reserve Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE.

(e) If there is a system-wide shortage of Regulation-Up, no shortage of Regulation-Down, no shortage of Contingency Reserve, and all zonal minimum requirements have been met:

(i) the Regulation-Up constraint Shadow Price is set equal to the Regulation-Up Demand Curve Price;

(ii) the Regulation-Up plus Contingency Reserve constraint Shadow Price is calculated normally and does not reflect the Contingency Reserve Demand Curve Price;

(iii) the Supplemental Reserve MCP and Spinning Reserve MCP shall not reflect the Contingency Reserve Demand Curve Price through the calculation described under Sections 8.3.4(2)(c) and 8.3.4(b) of this Attachment AE respectively; and

(iv) the Regulation-Up MCP shall reflect the Regulation-Up Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE.
(f) If there is a system-wide shortage of Regulation-Down, no shortage of Regulation-Up, no shortage of Contingency Reserve, and all zonal minimum requirements have been met:

(i) the Regulation-Down constraint Shadow Price is set equal to the Regulation-Down Demand Curve Price;

(ii) the Regulation-Up plus Contingency Reserve constraint Shadow Price is calculated normally and does not reflect the Contingency Reserve Demand Curve Price;

(iii) the Regulation-Up constraint Shadow Price is calculated normally and does not reflect the Regulation-Up Demand Curve Price;

(iv) the Supplemental Reserve MCP and Spinning Reserve MCP shall not reflect the Contingency Reserve Demand Curve Price through the calculation described under Sections 8.3.4(2)(c) and 8.3.4(b) of this Attachment AE respectively;

(v) the Regulation-Up MCP shall not reflect the Regulation-Up Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE; and

(vi) the Regulation-Down MCP shall reflect the Regulation-Down Demand Curve Price through the calculation described under Section 8.3.4(2)(d) of this Attachment AE.

(g) If there is a system-wide shortage of Ramp Capability Up, the Ramp Capability Up MCP will be set equal to the Ramp Capability Up Demand Curve price. The Ramp Capability Up Demand Curve price will be reflected in the LMP.

(h) If there is a system-wide shortage of Ramp Capability Down, the Ramp Capability Down MCP will be set equal to the Ramp Capability Down Demand Curve price. The Ramp Capability Down Demand Curve price will be reflected in the LMP.

(i) If there is a system-wide shortage of Uncertainty Reserve, the Uncertainty Reserve MCP will be set equal to the applicable Uncertainty Reserve...
Demand Curve Price. The Uncertainty Reserve Demand Curve price will be reflected in the LMP.

8.3.4.3 Operating Reserve Scarcity Factors

The Transmission Provider calculates and posts Contingency Reserve Scarcity Factors, Regulation-Up Scarcity Factors and Regulation-Down Scarcity Factors as described below.

(1) The Contingency Reserve Scarcity Factor varies based on the MW amount of Contingency Reserve shortage. The Contingency Reserve shortage MW values that result in changes to the scarcity price values are calculated by the Transmission Provider based on the projected Most Severe Single Contingency (MSSC) for the Operating Day in accordance with the following rules:

a. For Contingency Reserve shortages less than or equal to one-half of the SPP Reserve Sharing Group Contingency Reserve requirement above the MSSC, the Reserve Scarcity Factor will be set to 0.25.

b. For Contingency Reserve Shortages greater than one-half the SPP Reserve Sharing Group Contingency Reserve requirement above the MSSC but less than or equal to SPP Reserve Sharing Group Contingency Reserve requirement above the MSSC, the Contingency Reserve Scarcity Factor will be set to 0.5.

c. For Contingency Reserve Shortages greater than the SPP Reserve Sharing Group Contingency Reserve requirement above the MSSC, the Contingency Reserve Scarcity Factor will be set to 1.

(2) The Regulation-Up Scarcity Factor varies based on the MW amount of Regulation-Up shortage. The Regulation-Up shortage MW values that result in changes to the Scarcity Price values are calculated by the Transmission Provider using historical Regulation-Up deployment data in accordance with the following rules:
a. For Regulation-Up reserve shortages less than or equal to 30 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 1.

b. For Regulation-Up reserve shortages greater than 30 percent but less than or equal to 50 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 2.

c. For Regulation-Up reserve shortages greater than 50 percent but less than or equal to 70 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 3.

d. For Regulation-Up reserve shortages greater than 70 percent but less than or equal to 80 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 4.

e. For Regulation-Up reserve shortages greater than 80 percent but less than or equal to 90 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 5.

f. For Regulation-Up Reserve shortages greater than 90 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Pricing level will be set to the maximum Scarcity Pricing level described in Section 8.3.4.2(2)(b).

(3) The Regulation-Down Scarcity Factor varies based on the MW amount of Regulation-Down shortage. The Regulation-Down shortage MW values that result in changes to the Scarcity Price values are calculated by the Transmission Provider using historical Regulation-Down deployment data in accordance with the following rules:

a. For Regulation-Down reserve shortages less than 30 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 1.
b. For Regulation-Down reserve shortages greater than 30 but less than or equal to 50 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 2.

c. For Regulation-Down reserve shortages greater than 50 but less than or equal to 70 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 3.

d. For Regulation-Down reserve shortages greater than 70 but less than or equal to 80 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 4.

e. For Regulation-Down reserve shortages greater than 80 but less than or equal to 90 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 5.

f. For Regulation-Down reserve shortages greater than 90 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Pricing level will be set to the maximum Scarcity Pricing level described in Section 8.3.4.2(2)(c) of this Attachment AE.
8.3.4.4 Regulation Base Demand Price

On a monthly basis, the Transmission Provider calculates and posts a Regulation Base Demand Price as a function of the cost to commit a Resource to provide ramp or capacity to the market in accordance with the following rules:

1. Regulation Base Demand Price is the average cost per MW for all Resources to recover their qualified cold start-up, no-load, and Energy costs at their Minimum Normal Operating Limit or Minimum Discharge Limit, as applicable.

2. For each interval and Resource, a cold start-up time must be less than or equal to 10 minutes and the Real-Time commitment status must be Market, Reliability, or Self for the Resource costs to qualify for inclusion in the calculation.

3. By interval and Resource, the average cost per MW is based on the costs (cold start-up, no-load, and Energy) that would be incurred at the minimum load and minimum run time from three months of historical offer data.

The Transmission Provider may re-calculate the Regulation Base Demand Price more frequently than once a month as needed in order to reflect the operational cost of Resources if projected to be significantly different than historical based offer data.
8.5.9 Day-Ahead Make Whole Payment Amount

(1) The Day-Ahead make whole payment amount is a payment to an Asset Owner and is calculated for each Resource with an associated Day-Ahead Market Commitment Period that was committed by the Transmission Provider including commitments from the Multi-Day Reliability Assessment as defined under Section 4.5.3 of this Attachment AE. Asset Owners of Resources previously committed by a local transmission operator to address a Local Emergency Condition are eligible to receive a Day-Ahead Market make whole payment if such commitment is included in the Day-Ahead Market; except that, if the Market Monitor determines such Resources were selected in a discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, and such Resources were affiliated with the local transmission operator, then such Resources are not eligible to receive a Day-Ahead Market make whole payment. A payment is made to an Asset Owner when a Resource’s costs are greater than the Day-Ahead Market revenues received during the Resource’s Day-Ahead Market make whole payment eligibility period. The make whole payment is equal to this difference between those costs and revenues.

(2) A Resource’s Day-Ahead Market make whole payment eligibility period is equal to a Resource’s Day-Ahead Market Commitment Period except as defined herein. For Resources with an associated Day-Ahead Market Commitment Period that begins in one Operating Day and ends in the next Operating Day, two (2) Day-Ahead Market make whole payment eligibility periods are created. The first period begins in the first Operating Day in the hour that the Day-Ahead Market Commitment Period begins and ends in the last hour of the first Operating Day. The second period begins in the first hour of the next Operating Day and ends in the last hour of the Day-Ahead Market Commitment Period.

(3) The following cost recovery rules apply to each Day-Ahead Market make whole payment eligibility period. Offer costs are calculated using the Day-Ahead Market Offer prices in effect at the time the commitment decision was made except under the situation described under Section (b)(iiv) below.
(a) There may be more than one Day-Ahead Market make whole payment eligibility period for a Resource in a single Operating Day for which a charge or payment is calculated. A single Day-Ahead Market make whole payment eligibility period is contained within a single Operating Day.

(b) A Resource’s Day-Ahead Market commitment level offer costs include Start-Up Offer, Transition State Offer, and RUC remainder amount (as described in Section 8.5.9(3)(b)(v) of this Attachment AE) for a Day-Ahead Market make whole payment eligibility period in which that Resource is committed with a Day-Ahead Market Resource Offer commitment status under Section 4.1(10)(a), (b) or (c) of this Attachment AE, including commitments from the Multi-Day Reliability Assessment as described under Section 4.5.3 of this Attachment AE. The commitment level cost eligible for recovery is calculated by subtracting all Start-Up Offer cost and Transition State Offer cost associated with a Day-Ahead Market Resource Offer commitment status as described under Sections 4.1(10)(a) of this Attachment AE from all eligible commitment level Offer costs required to execute the Day-Ahead schedule associated with the Day-Ahead Market make whole payment eligibility period. The resulting difference represents either a charge or a payment and is a cost component when determining a Day-Ahead Market make whole payment.

(i) In any Day-Ahead Market make whole payment eligibility period for which the Day-Ahead Market SCUC algorithm did not consider the Resource’s Start-Up Offer in the original commitment decision, except Day-Ahead Start-Up Offer costs associated with the commitments made under Sections 4.5 and 5.1.2(1)(b) of this Attachment AE that caused an additional scheduled start, the Resource’s Start-Up Offer shall equal zero.

(ii) A Resource’s Day-Ahead Market Start-Up Offer cost is not eligible for recovery in the following Day-Ahead Market make whole payment eligibility periods:
(1) For any Day-Ahead make whole payment eligibility period for which a Resource is a Synchronized Resource prior to this commitment period at a time one (1) hour prior to that Resource’s Day-Ahead Market Commit Time in addition to the Resource’s Sync-To-Min Time unless the Day-Ahead Market make whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the one (1) hour in addition to the Resource’s Sync-To-Min Time; or

(2) For any Day-Ahead make whole payment eligibility period for which a Staggered Start Resource is a Synchronized Resource prior to this commitment period at a time two (2) hours prior to that Resource’s Day-Ahead Market Commit Time in addition to the Resource’s Sync-To-Min Time unless the Day-Ahead Market make whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the two (2) hours in addition to the Resource’s Sync-To-Min Time.

(iii) When a RUC commitment is made at a point in time after the existing Day-Ahead Market commitment was made, but the RUC commitment is scheduled for a time adjacent and prior to the existing Day-Ahead Market commitment, the cost considered at the point of adjacency between the RUC and Day-Ahead Market commitments will be allocated between the two commitments for make whole payment purposes as described in (1) and (2) below.

(1) The cost allocated to the RUC make whole payment will not be greater than the difference between: (a) the Day-Ahead Market Start-Up Offer and Transition State Offer costs at the adjacency point of the RUC and Day-Ahead Market commitment; and (b) Day-Ahead Market Start-Up
Offer and Transition State Offer costs associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(a) of this Attachment AE commitment at the adjacency point.

(2) The commitment level cost in the Day-Ahead Market make whole payment is reduced by the non-negative cost allocated to the RUC make whole payment.

(iv) A Resource’s Day-Ahead Market Transition State Offer costs for a Day-Ahead Market commitment are eligible for recovery in the Day-Ahead Market make whole payment eligibility period except when the Day-Ahead Market SCUC algorithm did not consider the Resource’s Transition State Offer in the Day-Ahead commitment decision unless Transition State Offers costs are associated with manual commitments as described under Sections 4.5.2 and 5.1.2 of this Attachment AE.

(v) As described under Section 8.6.5(3)(g) of this Attachment AE, to the extent that the full amount of the eligible RTBM Start-Up cost is not accounted for in the adjacent RUC make whole payment eligibility period, any remaining RTBM Start-Up cost is carried forward for recovery in the adjacent Day-Ahead make whole payment eligibility period.

(vi) When a Resource loses eligibility to recover a Day-Ahead Market Start-Up Offer cost for the reason described in Section 8.5.9(3)(b)(ii)(1) of this Attachment AE, to prevent overstatement of avoided costs, the commitment level cost is adjusted by the lesser of: (a) the Resource’s Start-Up Offer cost and Transition State Offer cost associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(a) of this Attachment AE commitments; or (b) the ineligible Day-Ahead Market Start-Up Offer cost.
(vii) For each Day-Ahead Market make whole payment eligibility period within an Operating Day, a Resource’s eligible Start-Up cost is divided by the lesser of (1) the Resource’s applicable Minimum Run Time rounded down to the nearest hour or (2) twenty-four (24) hours, to achieve an hourly proration for the purpose of allocating Start-Up costs across adjacent Day-Ahead commitments.

(1) If the number of participating hours of a Day-Ahead Market make whole payment eligibility period meets or exceeds the duration of the divisor as described in (vii) above, the full cost of the Start-Up Offer is included in the commitment level cost for the Day-Ahead Market make whole payment eligibility period.

(2) If the number of participating hours of a Day-Ahead Market make whole payment eligibility period is less than the duration of the divisor as described in (vii) above, the hourly proration is multiplied by the number of participating hours to achieve a single Start-Up Offer amount to be included in the commitment level cost for that Day-Ahead Market make whole payment eligibility period. Any remaining Day-Ahead Market Start-Up Offer cost will be included in the commitment level cost for the following and adjacent Day-Ahead Market make whole payment eligibility period in the next Operating Day.

(c) For an MCR, additional costs or revenues are incurred when the Resource has cleared Contingency Reserve, Ramp Capability Up, Ramp Capability Down, or Uncertainty Reserve in the Day-Ahead Market and must buy back that position in Real-Time at an average hourly Real-Time MCP. These costs or revenues will be considered as an adjustment when determining a Day-Ahead Market make whole payment. These costs or revenues must be incurred during a time period in the Day-Ahead Market
make whole payment eligibility period in which the Resource is transitioning in Real-Time due to a Day-Ahead scheduled transition that is not forced by the Resource Offer. The Market Participant may also be eligible for adjustments to a Day-Ahead Market make whole payment for costs or revenues incurred during transition if the Resource is transitioning in Real-Time in response to a local transmission operator to address a Local Emergency Condition, (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE) then such Resources are not eligible to receive an adjustment to a Day-Ahead make whole payment for these costs or revenues. In such cases, the adjustment is equal to the Real-Time MCP multiplied by the Day-Ahead Market cleared Contingency Resource, Ramp Capability Up, Ramp Capability Down, or Uncertainty Reserve MW amounts. Recovery of these costs of revenues is limited to the dispatch interval time periods defined by the Transition State Time submitted in the Resource Offer.

(d) If a Resource’s self-commitment period is less than the Resource’s Minimum Run Time, the Transmission Provider will relax the Resource’s Minimum Run Time to equal the self-commit period.

(e) If a Resource is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE in the Day-Ahead Market, the Resource will be eligible to recover applicable recurring costs as defined in Section 8.5.9(4)(a) of this Attachment AE for that period in the Day-Ahead Market make whole payment eligibility period.

(4) The payment to each Asset Owner for each eligible Settlement Location for a given Day-Ahead Market make whole payment eligibility period is calculated as follows:

\[
\text{Day-Ahead Make Whole Payment Amount} = \max(0, \text{Day-Ahead Make Whole Payment Cost Amount in the Day-Ahead Market Make Whole Payment Eligibility Period}) + \text{(Day-Ahead Make Whole Payment Revenue Amount in the...}
Day-Ahead Market Make Whole Payment Eligibility Period) + (Day-Ahead Make Whole Payment Commitment Cost)) * (-1)

(a) An Asset Owner’s Day-Ahead Make Whole Payment Cost Amount for each eligible Resource is equal to the sum for all hours in the Day-Ahead Market Make Whole Payment Eligibility Period of:

(i) Day-Ahead Market No-Load Offer,

(ii) Energy cost associated with cleared Resource Energy, including MSRs providing a market service, from Resource Energy Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Resource Energy by the cost of such Energy as calculated from the Resource’s Day-Ahead Market Energy Offer Curve,

(iii) Regulation-Up Service cost associated with cleared Regulation-Up Service from Regulation-Up Service Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Up Service by the cost of such Regulation-Up Service as calculated from the Resource’s Day-Ahead Market Regulation-Up Service Offer,

(iv) Regulation-Down Service cost, associated with cleared Regulation-Down Service from Regulation-Down Service Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Down Service by the cost of such Regulation-Down Service as calculated from the Resource’s Day-Ahead Market Regulation-Down Service Offer,

(v) Spinning Reserve cost, associated with: (1) cleared Spinning Reserve from Spinning Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Spinning Reserve by the Day-Ahead Spinning Reserve offer; and (2) cleared Spinning Reserve from Regulation-Up Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Up for Spinning Reserve by the
Day-Ahead Regulation-Up capability offer to the extent that Regulation-Up Service was cleared to meet the Spinning Reserve requirement. Such costs shall exclude Spinning Reserve and Regulation-Up costs associated with an MCR during a Day-Ahead Market scheduled transition time when the MCR is transitioning in the Real-Time Balancing Market,

(vi) Supplemental Reserve cost, associated with: (1) cleared Supplemental Reserve from Supplemental Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Supplemental Reserve by the Day-Ahead Supplemental Reserve Offer; (2) cleared Supplemental Reserve from Spinning Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Spinning Reserve for Supplemental Reserve by the Day-Ahead Spinning Reserve offer to the extent that Spinning Reserve was cleared to meet the Supplemental Reserve requirement; and (3) cleared Supplemental Reserve from Regulation-Up Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Up for Supplemental Reserve by the Day-Ahead Regulation-Up capability offer to the extent that Regulation-Up Service was cleared to meet the Supplemental Reserve requirement. Such costs shall exclude Supplemental Reserve, Spinning Reserve, and Regulation-Up costs associated with an MCR during a Day-Ahead Market scheduled transition time when the MCR is transitioning in the Real-Time Balancing Market,

(vii) Day-Ahead Potential Unused Regulation-Up Mileage Make Whole Payment as calculated under Section 8.6.19(1)(b) of this Attachment AE, and
(viii) Day-Ahead Potential Unused Regulation-Down Mileage Make Whole Payment as calculated under Section 8.6.20(1)(b) of this Attachment AE,

(ix) Day-Ahead Combined Cycle Spinning Reserve Adjustment which is a charge or payment, as described in Section 8.5.9(3)(c) of this Attachment AE, associated with an MCR, which is not eligible to clear Spinning Reserve in RTBM during a Real-Time transition between configurations which was scheduled in a Day-Ahead Market make whole payment eligibility period, and

(x) Day-Ahead Combined Cycle Supplemental Reserve Adjustment which is a charge or payment, as described in Section 8.5.9(3)(c) of this Attachment AE, associated with an MCR, which is not eligible to clear Supplemental Reserve in RTBM during a Real-Time transition between configurations which was scheduled in a Day-Ahead Market make whole payment eligibility period.

(b) An Asset Owner’s Day-Ahead Make Whole Payment Revenue Amount for each eligible Resource that is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE is equal to the sum for all hours in the Day-Ahead Market Make Whole Payment Eligibility Period of:

(i) Energy revenue associated with cleared Resource Energy, and MSRs providing a market service, from Resource Energy Offers as described under Section 5.1.3 of this Attachment AE, calculated by multiplying Resource Energy by Day-Ahead LMP at that Resource Settlement Location, and

(ii) The sum of the revenues calculated under Section 8.5.2, 8.5.3, 8.5.4, 8.5.26, 8.5.29, 8.6.19(1) and 8.6.20(1) of this Attachment AE for that eligible Resource.

(c) An Asset Owner’s Day-Ahead Make Whole Payment Commitment Cost Amount for each eligible Resource in the Day-Ahead Market Make Whole Payment Eligibility Periods is equal to:
(i) Day-Ahead Market Start-Up Offer or any RUC remainder amount as described in Section 8.6.5(3)(f) of this Attachment AE, plus

(ii) Day-Ahead Transition State Offer (for an MCR), plus

(iii) Any amount of Start-Up costs where the Resource loses eligibility to recover as described in Section 8.5.9(3)(b)(v) of this Attachment AE, minus

(iv) Any amount of shared Start-Up costs between Day-Ahead Market and RUC make whole payment eligibility periods as described in Section 8.5.9(3)(b)(ii) of this Attachment AE, minus

(v) All Start-Up and Transition State Offer costs associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(a) of this Attachment AE.
8.5.29 Day-Ahead Uncertainty Reserve Amount

A Day-Ahead Market payment for cleared Uncertainty Reserve will be calculated at each Settlement Location for each Asset Owner for each hour as follows:

\[
\text{Day-Ahead Uncertainty Reserve Hourly Amount} = \left((\text{Day-Ahead MCP}) \times (\text{Day-Ahead Cleared Uncertainty Reserve Hourly Quantity})\right) \times (-1)
\]

(1) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Uncertainty Reserve associated with the Reserve Zone in which the applicable Resource is located.

(2) An Asset Owner's Day-Ahead Cleared Uncertainty Reserve Hourly Quantity is the MW quantity associated with cleared Uncertainty Reserve Offers as described under Section 5.1.3 of this Attachment AE.
### 8.5.30 Day-Ahead Uncertainty Reserve Distribution Amount

A Day-Ahead Market charge for Uncertainty Reserve procurement costs calculated under Section 8.5.29 of this Attachment AE will be calculated at each Reserve Zone for each Asset Owner for each hour as follows:

\[
\text{Day-Ahead Uncertainty Reserve Hourly Distribution Amount} = \frac{\text{((Day-Ahead Uncertainty Reserve Obligation) \times (Day-Ahead Uncertainty Reserve Procurement Rate))}}{\text{((Reserve Zone MCP \times Total of cleared Uncertainty Reserve for that Reserve Zone) + (Weighted Average MCP of all Exporting Zones \times (Sum of Asset Owners’ Day-Ahead Uncertainty Reserve Obligations for that Reserve Zone - Total of cleared Uncertainty Reserve for that Reserve Zone)) / (Sum of Asset Owners’ Day-Ahead Uncertainty Reserve Obligations for that Reserve Zone))}}
\]

1. An Asset Owner’s Day-Ahead Uncertainty Reserve Obligation in each Reserve Zone is equal to the system wide total of all cleared Uncertainty Reserve multiplied by the Asset Owner Reserve Zone Load Ratio Share, adjusted up or down to account for any Bilateral Settlement Schedules for Uncertainty Reserve.

2. For a Reserve Zone that clears more Uncertainty Reserve than the sum of Asset Owners’ Day-Ahead Uncertainty Reserve Obligations for that Reserve Zone, the zone is deemed an exporting zone and the Day-Ahead Uncertainty Reserve Procurement Rate is equal to the Uncertainty Reserve MCP for that Reserve Zone.

3. For a Reserve Zone that clears less Uncertainty Reserve than the sum of Asset Owners’ Day-Ahead Uncertainty Reserve Obligations for that Reserve Zone, the Day-Ahead Uncertainty Reserve Procurement Rate is as follows:
8.6.5 Reliability Unit Commitment Make Whole Payment Amount

(1) Asset Owners of Resources committed by the Transmission Provider during the RUC processes, are eligible to receive a RUC make whole payment. Asset Owners of Resources committed by a local transmission operator during the RUC processes to address a Local Emergency Condition are eligible to receive a RUC make whole payment, except that, if the Market Monitor determines such Resources were selected in a discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, and such Resources were affiliated with the local transmission operator, then such Resources are not eligible to receive a RUC make whole payment. A RUC make whole payment is made to the Asset Owner when the sum of a Resource’s costs associated with actual Energy and cleared RTBM Operating Reserve is greater than the RTBM revenues received over the Resource’s RUC make whole payment eligibility period. Recovery of such compensation shall be collected in accordance with Section 8.6.7 of this Attachment AE.

(2) A Resource’s RUC make whole payment eligibility period is equal to the set of a Resource’s contiguous RUC Commitment Periods and adjacent Day-Ahead Market commitment periods except:

(a) For Resources with a set of contiguous Day-Ahead and RUC Commitment Periods that continue from one Operating Day to the next Operating Day, a RUC make whole payment eligibility period is created for each Operating Day in which there is a RUC commitment. A RUC make whole payment eligibility period is created for each Operating Day with a RUC commitment. The start of a RUC make whole payment eligibility period is the later of (1) beginning of the Operating Day or (2) the beginning of the set of contiguous Day-Ahead Market and RUC commitments. The end of a RUC make whole payment eligibility period is the earlier of (1) the end of the set of contiguous Day-Ahead Market and RUC commitments or (2) the end of the Operating Day; or

(b) For an MCR that cleared in the Day-Ahead Market and was transitioned to a different configuration in Real-Time by the Transmission Provider or by
a local transmission operator to address a Local Emergency Condition (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE), the costs in the intervals preceding the RUC commitment for the purpose of buying back Operating Reserve products while the Resource transitions to the RUC committed configuration, as defined by the Transition State Time of the Resource’s offer parameters in Section 4.1(9) of this Attachment AE, are included in the RUC make whole payment calculation.

(3) The following cost recovery rules apply to each RUC make whole payment eligibility period. Resource production costs are calculated using the RTBM Offer prices in effect at the time the commitment decision was made for start-up, transitions, no-load, and minimum-energy; and the RTBM Offer price in effect at the solving of a dispatch interval for the Energy above minimum energy, Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve.

(a) If the Transmission Provider cancels a Commitment Instruction prior to the start of the associated RUC make whole payment eligibility period, the Asset Owner will receive reimbursement for a time-based pro-rata share of the Resource’s RTBM Start-Up Offer unless precluded by Section 8.6.5(3)(e)(i) of this Attachment AE. Asset Owners may request additional compensation through submittal of actual cost documentation to the Transmission Provider. The Transmission Provider will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

(b) In order to receive the full amount of Start-Up Offer recovery within a RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in at least one Dispatch Interval in the RUC make whole payment eligibility period.

(c) In order to receive recovery of No-Load Offer costs in any Dispatch Interval in the RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in that Dispatch Interval.
(d) There may be more than one RUC make whole payment eligibility period for a Resource in a single Operating Day. A single RUC make whole payment eligibility period is contained within a single Operating Day.

(e) A Resource’s RUC commitment level offer costs include Start-Up Offer cost and Transition State Offer cost for a RUC make whole payment eligibility period in which that Resource is committed with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a), (b) or (c) of this Attachment AE. The commitment level cost eligible for recovery is calculated by subtracting: (1) all Start-Up Offer cost and Transition State Offer cost associated with the schedule created by combining all Day-Ahead Market commitments with a Day-Ahead Market Resource Offer commitment status as defined under Section 4.1(10)(a), (b) or (c) of this Attachment AE contained within a RUC make whole payment eligibility period and all RUC commitments that are associated with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a) of this Attachment AE within a RUC make whole payment eligibility period; from (2) all eligible commitment level offer costs associated with the final Resource schedule in a RUC make whole payment eligibility period. The resulting difference can represent a charge or a payment and is considered as an adjustment when determining a RUC make whole payment.

(i) Except for an MCR that is committed by RUC in a different configuration than in the Day-Ahead Market, when a RUC make whole payment eligibility period is created after a Day-Ahead make whole payment eligibility period and is adjacent and preceding that Day-Ahead make whole payment eligibility period where the Day-Ahead Start-Up Offer Amount defined in Section 8.5.9(3)(b)(i) of this Attachment AE was considered, the Day-Ahead Start-up Offer Amount is used in place of the RUC Start-up costs.
(ii) In any RUC make whole payment eligibility period for which the RUC SCUC did not consider the Resource’s Start-Up Offer in the original commitment decision, except for commitments made as described under Sections 5.2.2(3), 6.1.2(3) and 6.1.2(4) of this Attachment AE, the Resource’s Start-Up Offer shall equal zero.

(iii) A Resource’s RTBM Start-Up costs are not eligible for recovery in the following RUC make whole payment eligibility periods:

1. Any RUC make whole payment eligibility period for which a Resource is a Synchronized Resource prior to this commitment period at a time one (1) hour prior to that Resource’s RUC Commit Time in addition to the Resource’s Sync-To-Min Time unless the RUC make whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the one (1) hour in addition to the Resource’s Sync-To-Min Time; or

2. For any RUC make whole payment eligibility period for which a Staggered Start Resource is a Synchronized Resource prior to this commitment period at a time two (2) hours prior to that Resource’s RUC Commit Time in addition to the Resource’s Sync-To-Min Time unless the RUC market whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the two (2) hours in addition to the Resource’s Sync-To-Min Time; or

3. For any RUC make whole payment eligibility period for which the commitment is made in conjunction with RTBM offline Uncertainty Reserve clearing.

(iv) When there is a cost transferred from the Day-Ahead Market make whole payment as described in Section 8.5.9(3)(b)(iii) of this Attachment AE, the commitment level cost in the RUC make
whole payment is increased by the amount allocated to the RUC make whole payment as described in Section 8.5.9(3)(b)(iii) of this Attachment AE.

(v) In any RUC make whole payment eligibility period for which the RUC SCUC considered the Resource’s Transition State Offer in the original commitment decision, or the RTBM Transition State Offer is associated with a manual commitment as described under Sections 5.2.2(3), 6.1.2(3) and 6.1.2(4) of this Attachment AE, the Transition State Offer cost is eligible for recovery when the following conditions are met:

1. In at least one Dispatch Interval during the scheduled configuration period, the Resource is in the target “from” configuration and the Resource must be a Synchronized Resource; and
2. In at least one Dispatch Interval during the scheduled configuration period, the Resource is in the target “to” configuration and the Resource must be a Synchronized Resource.

(vi) If the Transmission Provider cancels a transition between configurations prior to the scheduled transition associated with a RUC make whole payment eligibility period, the Asset Owner will be eligible to recover a time-based pro-rata share of the Resource’s RTBM Transition State Offer through the RUC make whole payment unless precluded by Section 8.6.5(3)(e)(i) of this Attachment AE. Asset Owners may request additional compensation through submittal of actual cost documentation to the Transmission Provider. The Transmission Provider will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.
(vii) When a Resource loses eligibility to recover a Start-Up Offer cost for the reason described in Section 8.6.5(3)(e)(iii)(1) of this Attachment AE, or loses eligibility to recover Transition State Offer costs for the reason described in Section 8.6.5(3)(v) of this Attachment AE, to prevent overstating avoided costs, the commitment level cost is adjusted by the lesser of: (1) its Start-Up Offer cost and Transition State Offer cost associated with commitments that have a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a) of this Attachment AE; or (2) the ineligible RTBM Start-Up Offer cost plus the ineligible Transition State Offer costs.

(viii) For each RUC make whole payment eligibility period within an Operating Day, a Resource’s eligible Start-Up cost is divided by the lesser of (1) the hours of RUC commitment within the Resource’s applicable Minimum Run Time multiplied by twelve (12), rounded down to the nearest whole interval, or (2) twenty-four (24) hours multiplied by twelve (12), to achieve a Dispatch Interval proration for the purpose of allocating Start-Up costs across adjacent Day-Ahead Market or RUC make whole payment eligibility periods.

1. If the number of participating Dispatch Interval meets or exceeds the duration of the divisor as described in (viii) above, the full cost of the Start-Up Offer is included in the commitment level cost for the RUC make whole payment eligibility period.

2. If the number of participating Dispatch Intervals is less than the duration of the divisor as described in (viii) above, the proration is multiplied by the number of participating Dispatch Intervals to achieve a single Start-Up Offer amount to be included in the commitment level cost for that RUC make whole payment eligibility period. Any
remaining eligible RUC Start-Up cost will be included in the commitment level cost for the following and adjacent Day-Ahead Market make whole payment eligibility period as described in Section 8.6.5(3)(f) of this Attachment AE or the following and adjacent RUC make whole payment eligibility period in the next Operating Day.

(f) If the Resource has been committed in the Day-Ahead Market in a period adjacent to and following a RUC make whole payment eligibility period to the extent that the full amount of the eligible RTBM Start-Up cost is not accounted for in the RUC make whole payment eligibility period, any remaining eligible RTBM Start-Up cost is carried forward for recovery in the Day-Ahead make whole payment eligibility period.

(g) If a Resource has operated outside of its Operating Tolerance in any Dispatch Interval, any cost associated with energy injection or withdrawal above the Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Section 8.6.5(4)(d) of this Attachment AE.

(h) If a Resource becomes non-dispatchable in any Dispatch Interval, any cost associated with energy injection or withdrawal above the Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Section 8.6.5(4)(d) of this Attachment AE.

(i) (1) If a Resource’s minimum operating limit is increased above the Resource’s minimum operating limit that was used to make the commitment decision, the increase is greater than the Resource’s Operating Tolerance and the Resource remains dispatchable in any Dispatch Interval, any cost associated with energy injection or withdrawal above the Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Section 8.6.5(4)(d) of this Attachment AE, or (2) if a Resource is committed and subsequent to that commitment, the Resource’s originally
submitted limits are modified such that the Resource’s availability switches from injection to withdrawal, any cost associated with energy withdrawal below the Resource’s economic operating point resulting from changing its availability from injection to withdrawal is not eligible for recovery for the Dispatch Interval for which such cost is calculated. If a Resource is committed and subsequent to that commitment, the Resource’s originally submitted limits are modified such that the Resource’s availability switches from withdrawal to injection, any cost associated with energy injection above the Resource’s economic operating point resulting from changing its availability from withdrawal to injection is not eligible for recovery for the Dispatch Interval for which such cost is calculated.

(j) If a Resource’s self-commitment period is less than the Resource’s Minimum Run Time, the Transmission Provider will relax the Resource’s Minimum Run Time to equal the self-commit period.

(k) If a Resource is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE in the RTBM, the Resource will be eligible to recover applicable recurring costs as defined in Section 8.6.5(4)(b) of this Attachment AE for that period in the RUC make whole payment eligibility period.

(l) For an MCR, additional costs of revenues incurred when the Resource has cleared Operating Reserve in the Day-Ahead Market and must buy back that position in Real-Time will be considered as an adjustment when determining a RUC make whole payment. These costs or revenues must be incurred during time periods in which the Resource is ineligible to clear Operating Reserve products due to transitioning between configurations in Real-Time where at least one configuration is the result of a RUC commitment, and the transition is not forced by the Resource Offer. The Market Participant may also be eligible to recover Operating Resource product buy back costs or revenue incurred during a Real-Time transition if the Resource is transitioned by a local transmission operator to address a
Local Emergency Condition (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE), then such Resources are not eligible to recover any costs or revenues associated with the transition as part of a RUC make whole payment. In such cases, the adjustment is equal to the sum of the cleared Day-Ahead Market Operating Reserve revenue as calculated from the Day-Ahead Operating Reserve MCP and the cleared incremental RTBM Operating Reserve revenue as calculated from the RTBM Operating Reserve MCPs. For Contingency Reserve, Ramp Capability Up, Ramp Capability Down, and Uncertainty Reserve the adjustment is limited to the time period defined as the transition State Time submitted in the Resource Offer. For Regulation-Up and/or Regulation-Down, the adjustment is limited to all Dispatch Intervals within the transition hour.

(4) The payment to each Asset Owner for each eligible Settlement Location for a given RUC make whole payment eligibility period is calculated as follows:

\[
\text{RUC Make Whole Payment Amount} = \max \left\{ \text{Either Zero or (RUC Make Whole Payment Commitment Cost Amount + RUC Make Whole Payment Cost Amount in the RUC Make Whole Payment Eligibility Period + RUC Make Whole Payment Revenue Amount in the RUC Make Whole Payment Eligibility Period – Uninstructed Resource Deviation Cost Disallowance – Non-Dispatchable Cost Disallowance – Minimum Limit Cost Disallowance + Real-Time Combined Cycle Operating Reserve Adjustment Amounts)} \right\}
\]

(a) An Asset Owner’s Real-Time Make Whole Payment Commitment Cost Amount for each eligible Resource in the RUC make whole payment eligibility period is equal to:

(i) Start-Up Offer used to make the commitment decision which was committed by the Transmission Provider or by a local transmission operator to address a Local Emergency Condition (unless such commitment instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE); plus
(ii) The Transition State Offer used to make the transition decision for an MCR that cleared in the Day-Ahead Market or committed by the RUC process that were transitioned by the Transmission Provider into a different configuration in Real-Time or transitioned by a local transmission operator to address a Local Emergency Condition (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE); plus

(iii) Real-Time Cancelled Transition Amount as described in Section 8.6.5(3)(e)(vi) of this Attachment AE; plus

(iv) Amount of shared Start-Up costs between Day-Ahead Market and RUC make whole payment eligibility periods as described in Section 8.5.9(3)(b)(iii) of this Attachment AE; plus

(v) Amount of costs where the Resource loses eligibility to recover as describe in Section 8.6.5(3)(e)(vii) of this Attachment AE, minus

(vi) The sum of all Start-Up Offer cost and Transition State Offer cost associated with the schedule created by combining (1) all Day-Ahead Market commitments with a Day-Ahead Market Resource Offer commitment status as defined under Section 4.1(10)(a), (b) or (c) of this Attachment AE contained within a RUC make whole payment eligibility period and (2) all RUC commitments that are associated with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a) of this Attachment AE within a RUC make whole payment eligibility period.

(b) An Asset Owner’s RUC Make Whole Payment Cost Amount for each eligible Resource is equal to the sum for all Dispatch Intervals in the RUC commitment of:

(i) No-Load Offer used to make the RUC commitment decision, less any Day-Ahead Market No-Load from an MCR resulting from a different Day-Ahead Market committed configuration where the No-Load Offer shall be included as zero for Dispatch Intervals
constituting the larger of the Uncertainty Reserve response time or Minimum Run Time of a RUC commitment made in conjunction with offline Uncertainty Reserve clearing;

(ii) Energy cost at minimum injection or withdrawal as calculated from the Energy Offer Curve used to make the commitment decision where this Energy cost at minimum shall be included as zero for Dispatch Intervals constituting the larger of the Uncertainty Reserve response time or Minimum Run Time of a RUC commitment made in conjunction with offline Uncertainty Reserve clearing;

(iii) Energy cost above minimum injection or withdrawal as calculated from the Energy Offer Curve that applied to the current Dispatch Interval;

(iv) For MCRs, the Energy cost shall be calculated from the Energy Offer Curve used in the Day-Ahead Market from zero to the lesser of (1) Day-Ahead Market cleared Energy or (2) the submitted meter in Real-Time, multiplied by (-1);

(v) For Resources (other than MCRs cleared in the Day-Ahead Market that were committed into a different configuration in Real-Time), Operating Reserve cost, including the impact from product substitution as described under Section 3.1.7 of this Attachment AE, associated with cleared Real-Time Operating Reserve. Excess Regulation-Up Mileage and Excess Regulation-Down Mileage as calculated from the Operating Reserve Offers, except when those costs are associated with self-scheduled Operating Reserve which is greater than or equal to the amount of Operating Reserve cleared, in which case all three of these costs shall be set equal to zero;

(vi) For an MCR that was cleared in the Day-Ahead Market and was committed into a different configuration in Real-Time and is not transitioning into that configuration, the Operating Reserve cost,
including the impact from product substitution as described under Section 3.1.7 of this Attachment AE, associated with cleared Real-Time Operating Reserve minus Day-Ahead Operating Reserve cost, including the impact from product substitution as described under Section 3.1.7 of this Attachment AE, associated with the lesser of (1) cleared Real-Time Operating Reserve or (2) cleared Day-Ahead Operating Reserve, except when self-scheduled Operating Reserve is less than or equal to the amount of Real-Time Operating Reserve cleared then the Operating Reserve cost shall be set equal to zero;

(vii) Real-Time Potential Regulation-Up Unused Mileage Make Whole Payment as calculated under Section 8.6.19(2)(b) of this Attachment AE; and

(viii) Real-Time Potential Regulation-Down Unused Mileage Make Whole Payment as calculated under Section 8.6.20(2)(b) of this Attachment AE.

(c) An Asset Owner’s RUC Make Whole Payment Revenue Amount for each eligible Resource that is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE is equal to the sum of the following for all Dispatch Intervals in the RUC commitment:

(i) Dispatch Interval revenue associated with Energy calculated by multiplying actual Dispatch Interval Energy injection or withdrawal by Real-Time LMP, except for MCRs that cleared in the Day-Ahead Market and were transitioned into a different configuration in Real-Time, in which case such revenue is calculated by multiplying Real-Time LMP by the incremental increase of the actual Dispatch Interval Energy injection or withdrawal above the Day-Ahead cleared Energy;

(ii) the sum of the revenues calculated under Sections 8.6.3 and 8.6.4 of this Attachment AE for that eligible Resource;
(iii) Energy revenue associated with payments made under Section 8.6.6 of this Attachment AE;
(iv) amounts associated with settlement made under Section 8.6.15 of this Attachment AE;
(v) Real-Time Unused Regulation-Up Mileage Make Whole Payment as calculated under Section 8.6.19(2) of this Attachment AE;
(vi) Real-Time Unused Regulation-Down Mileage Make Whole Payment as calculated under Section 8.6.20(2) of this Attachment AE;
(vii) Real-Time Regulation-Up Service Revenue as calculated under Section 8.6.19(2)(a)(i) of this Attachment AE;
(viii) Real-Time Regulation-Down Service Revenue as calculated under Section 8.6.20(2)(a)(i) of this Attachment AE;
(ix) Excess Regulation-Up Mileage Dispatch Interval Amount as calculated under Section 8.6.2(1)(a)(v) of this Attachment AE, multiplied by (-1);
(x) Excess Regulation-Down Mileage Dispatch Interval Amount as calculated under Section 8.6.2(2)(a)(v) of this Attachment AE, multiplied by (-1);
(xi) the sum of the revenues calculated under Section 8.6.26 of this Attachment AE; and
(xii) Real-Time Uncertainty Reserve revenue as calculated under Section 8.6.29 of this Attachment AE.

(d) An Asset Owner’s Uninstructed Resource Deviation Cost Disallowance, Non-Dispatchable Cost Disallowance, or Minimum Limit Cost Disallowance is equal to the positive difference between the Resource’s Energy cost at actual injection or withdrawal as calculated from the Resource’s current Dispatch Interval Energy Offer Curve and the Resource’s Energy cost at the Resource’s economic operating point as calculated from the Resource’s current Dispatch Interval Energy Offer Curve.
(e) A Resource’s economic operating point is the MW injection or withdrawal where the cost on the Resource’s current Dispatch Interval Energy Offer Curve first exceeds the Real-Time DLMP for that Resource.

(f) For MCRs that have been transitioned into a different configuration in Real-Time and are transitioning into that configuration, the Real-Time Combined Cycle Operating Reserve Adjustment Amount shall be equal to the sum of the cleared Day-Ahead Market Operating Reserve revenue as calculated from the Day-Ahead Operating Reserve MCP and the cleared incremental RTBM Operating Reserve revenue as calculated from the RTBM Operating Reserve MCPs.
8.6.29 Real-Time Uncertainty Reserve Amount

(1) An RTBM payment or charge for deviations between cleared RTBM Uncertainty Reserve and cleared Day-Ahead Market Uncertainty Reserve will be calculated at each Settlement Location by Asset Owner for each Dispatch Interval and hour as follows:

(a) Real-Time Uncertainty Reserve Dispatch Interval Amount =

\[ \left( \text{Real-Time MCP} \times \left( \text{Real-Time Cleared Uncertainty Reserve Dispatch Interval Quantity} - \text{Day-Ahead Uncertainty Reserve Hourly Quantity}\right) \right) / 12 \times (-1) \]

(i) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Uncertainty Reserve associated with the Reserve Zone in which the applicable Resource is located.

(ii) Asset Owner Real-Time Cleared Uncertainty Reserve Dispatch Interval Quantity is the MW quantity associated with cleared Uncertainty Reserve as described under Section 6.2.3 of this Attachment AE.

(iii) Asset Owner Day-Ahead Cleared Uncertainty Reserve Hourly Quantity is the MW quantity associated with cleared Day-Ahead Market Uncertainty Reserve as described under Section 5.1.3 of this Attachment AE.

(b) Real-Time Uncertainty Reserve Hourly Amount =

Sum of Real-Time Uncertainty Reserve Dispatch Interval Amount over all Dispatch Intervals in the Hour.

(2) If a Resource is mitigated for the Uncertainty Reserve product, is subsequently committed in conjunction with RTBM offline Uncertainty Reserve clearing, and Uncertainty Reserve mitigation caused reduced Uncertainty Reserve payments which did not cover the Resource costs excluded from the make whole payment due to the Uncertainty Reserve related commitment then the Resource may file a dispute for such mitigation caused shortfall.
8.6.30 Real-Time Uncertainty Reserve Distribution Amount

(1) An RTBM payment or charge will be calculated by Asset Owner at each Settlement Location for each hour for the purposes of funding the payments made under Section 8.6.29 of this Attachment AE as follows:

Real-Time Uncertainty Reserve Distribution Amount =

\[ [(\text{Real-Time Uncertainty Reserve Amount}) \times (\text{Real-Time Load Ratio Share})] \times (-1) \]

(a) The Real-Time Uncertainty Reserve Amount shall be equal to the sum of the all payments made under Section 8.6.29 of this Attachment AE for Uncertainty Reserve procurement for the hour.

(b) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.
8.6.31 **Real-Time Uncertainty Reserve Non-Performance Amount**

An RTBM payment or charge will be calculated at each Resource Settlement Location for each Asset Owner for each Dispatch Interval when a Resource with cleared RTBM Uncertainty Reserve does not operate in a responsive manner.

When a Resource with cleared online Uncertainty Reserve in the current Dispatch Interval is not dispatchable in one or more of the subsequent Dispatch Intervals within the Uncertainty Reserve response time following the current Dispatch Interval, except by Transmission Provider instruction, such as an OOME or decommitment, which prevents the Resource from being as seen as dispatchable, the amount will be determined as follows:

Real-Time Uncertainty Reserve Non-Performance Amount =

Real-Time Uncertainty Non-Performance Ratio * \[\left[\left(\text{Maximum of \[Either Zero or ((Day-Ahead MCP for Uncertainty Reserve) \times (Day-Ahead Cleared Uncertainty Reserve Hourly Quantity) + (Real-Time MCP for Uncertainty Reserve) \times (Real-Time Cleared Uncertainty Reserve Dispatch Interval Quantity – Day-Ahead Cleared Uncertainty Reserve Hourly Quantity)})\]}\right]/12\].

1. Real-Time Uncertainty Non-Performance Ratio portion of non-dispatchable intervals in the subsequent Dispatch Intervals within the Uncertainty Reserve response time.

2. Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Uncertainty Reserve associated with the Reserve Zone in which the applicable Resource is located.

3. Real-Time MCP, as defined under Section 1 of this Attachment AE, for Uncertainty Reserve associated with the Reserve Zone in which the applicable Resource is located.

4. An Asset Owner’s Day-Ahead Cleared Uncertainty Reserve Hourly Quantity is the MW quantity associated with cleared Uncertainty Reserve as described under Section 5.1.3 of this Attachment AE.

5. An Asset Owner’s Real-Time Cleared Uncertainty Reserve Dispatch Interval Quantity is the MW quantity associated with cleared Uncertainty Reserve as described under Section 6.2.3 of this Attachment AE.
When a Resource with cleared offline Uncertainty Reserve fails to start when called on in association with Uncertainty Reserve, the amount will be determined as follows in each interval:

Real-Time Uncertainty Reserve Non-Performance Amount =

If the Resource failed to start and was ineligible to recover startup cost associated within an offline uncertainty commitment, then the startup cost distributed equally over the larger of the Minimum Run Time or the Uncertainty Reserve response time during a single Operating Day of the eligibility period + [if the Resource was offline in a committed interval in which it was not eligible to recover no-load and Energy at minimum costs due to being associated with an offline uncertainty commitment, the as-committed No-Load Offer + as-committed Energy Offer at minimum cost)/12].
8.6.32 Real-Time Uncertainty Reserve Non-Performance Distribution Amount

An RTBM payment or charge will be calculated for each Asset Owner at each Settlement Location for each hour in order to distribute the funds collected under Section 8.6.31 of this Attachment AE. The Asset Owner amount is calculated as follows:

Real-Time Uncertainty Reserve Non-Performance Distribution Amount =
[(Real-Time Uncertainty Reserve Non-Performance Amount) * (Real-Time Load Ratio Share)] * (-1)

(1) The Real-Time Uncertainty Reserve Non-Performance Amount shall be equal to the sum of all charges made under Section 8.6.31 of this Attachment AE for each hour.

(2) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.

This section sets forth the market power mitigation measures that are applied in the Day-Ahead Market, Reliability Unit Commitment processes and the Real-Time Balancing Energy Markets, collectively referred to as the Energy and Operating Reserve Markets.

3.1 Local Market Power Test

A Resource satisfying at least one of the following conditions is determined to have local market power:

(1) The Resource is located in a Frequently Constrained Area, as described in Section 3.1.1, and one or more of the transmission constraints that define the Frequently Constrained Area is binding or the Reserve Zone that defines the area is binding;

(2) The Resource is not in a Frequently Constrained Area and
   (a) has a Resource-to-Load-Distribution factor less than or equal to negative five percent (-5%) relative to a binding transmission constraint; or
   (b) is located in a binding Reserve Zone;

(3) The Resource is committed, or the Multi-Configuration Resource (“MCR”) is transitioned, as defined in Attachment AE, to address a Local Reliability Issue.

3.1.1 Frequently Constrained Areas

A Frequently Constrained Area is an electrical area identified by the Market Monitor that is defined by one or more binding transmission constraints or binding Reserve Zone constraints that are expected to be binding for at least five-hundred (500) hours during a given twelve (12)-month period and within which one (1) or more suppliers are pivotal. All Frequently Constrained Area designations along with supporting analysis shall be posted on the Transmission Provider’s website.

3.1.1.1 Pivotal Supplier Test

A supplier is pivotal when the energy output or provision of operating reserves by any or some of its Resources jointly must be
increased or decreased to resolve the binding transmission constraint or binding Reserve Zone constraint during some or all hours. This will be determined utilizing transmission load flow cases or RTBM market cases reflecting a variety of market conditions.

These load flow or market cases will be used to estimate: (i) the generation shift factors for all relevant Resources and relevant resources outside the SPP Balancing Authority Area relative to each potentially constrained flowgate; (ii) the capability of all Resources to meet the requirements of each binding Reserve Zone constraint; (iii) the base loadings of Resources; (iv) the base allocation of Operating Reserves on Resources; and (v) the base flows on each flowgate. A supplier is pivotal when a binding transmission constraint or a binding Reserve Zone constraint cannot be relieved by changing the base loadings for other suppliers’ Resources.

3.1.1.2 Initial Designation of Frequently Constrained Areas

The Market Monitor will define and recommend the Frequently Constrained Areas to the SPP Board of Directors prior to the start of the Integrated Marketplace.

3.1.1.3 Changes to Frequently Constrained Area Designation

The Market Monitor shall reevaluate the Frequently Constrained Areas at least annually. A reevaluation may be performed more frequently if the Market Monitor believes that conditions have changed with respect to the binding transmission constraints or binding Reserve Zone constraints that define a Frequently Constrained Area, or if congestion on constraints that are not designated as a Frequently Constrained Area warrant a new analysis. The Transmission Provider may also propose an area be designated or undesignated as a Frequently Constrained Area to the Market Monitor. The Market Monitor will post the updated
Frequently Constrained Area information along with the associated analysis on the Transmission Provider’s website at least 14 calendar days prior to the Frequently Constrained Area updates becoming effective and will notify Market Participants of the posting. Market Participants may contact the MMU within the 14 day posting period if there are concerns with the Market Monitor’s proposed updates. The Market Monitor will consider and respond to Market Participant concerns and will make updates if needed. The Market Monitor will notify Market Participant when updates become effective.

3.2 Mitigation Measures for Energy Offer Curves

Mitigated Energy Offer Curves shall be submitted on a daily basis by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. For MCRs, for which a single configuration allows physical units to be swapped (e.g., Combustion Turbine 2 for Combustion Turbine 1), the costs used in the mitigated offer development for that configuration shall be those of the least cost physical unit that is available and can be swapped in such configuration. The mitigated Energy Offer Curve may be updated up to the close of the Day-Ahead Market as defined in Section 5.1 of Attachment AE of this Tariff for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Energy Offer Curve may be updated until the Day-Ahead RUC begins. For Resources committed by the Day-Ahead Market, the mitigated Energy Offer Curve submitted as of the close of the Day-Ahead Market will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day unless an exception is allowed in Section 3.2(J) of this Attachment AF; for all other Resources the mitigated Energy Offer Curve submitted at the time the Day-Ahead RUC begins will apply to the Day-Ahead RUC on the day before the Operating Day, and the Intra-Day RUC processes and the RTBM on the Operating Day. For the pricing SCED, the composite Energy Offer Curve and mitigated composite Energy Offer Curve will be calculated and used by the Transmission Provider for FSRs in the
Day-Ahead Market and RTBM as described in Section 3.3.1 of Attachment AE of this Tariff.

A. For a Resource with an Energy Offer Curve greater than or equal to $25/MWh that was not committed to address a Local Reliability Issue, the conduct thresholds are as follows:
   
   (1) For a Resource located in a Frequently Constrained Area, the conduct threshold is a 17.5% increase above the mitigated Energy Offer Curve;

   (2) For a Resource not located in a Frequently Constrained Area, the conduct threshold is a 25% increase above the mitigated Energy Offer Curve.

B. For a Resource with an Energy Offer Curve greater than or equal to $25/MWh that was not committed to address a Local Reliability Issue, the Transmission Provider shall apply mitigation measures by replacing the Energy Offer Curve with the mitigated Energy Offer Curve if:
   
   (1) The Resource’s Energy Offer Curve exceeds the mitigated Energy Offer Curve by the applicable conduct threshold; and

   (2) The Resource has local market power as determined in Sections 3.1(1) or 3.1(2); and

   (3) The Resource either:

      (a) Fails the Market Impact Test as described in Section 3.7, or

      (b) Is manually committed by the Transmission Provider or by a local transmission operator.

   A Resource with an Energy Offer Curve below $25/MWh shall not be subject to mitigation measures on its Energy Offer Curve for economic withholding.

C. For a Resource with an Energy Offer Curve greater than or equal to $25/MWh that has local market power as determined in Section 3.1(3), the Transmission Provider shall apply mitigation measures by placing a cap on the Energy Offer Curve of 10% above the mitigated Energy Offer Curve. A Resource with an Energy Offer Curve below $25/MWh shall
not be subject to mitigation measures on its Energy Offer Curve for economic withholding.

D. The mitigated energy offer shall be the Resource’s short-run marginal cost of producing energy as determined by the unit’s heat rate or similar production efficiency ratio; fuel costs and the costs related to fuel usage, such as transportation and emissions costs (“total fuel related costs”); and Energy Offer Curve (“EOC”) variable operations and maintenance costs (“VOM”) as detailed in the Market Protocols and the charges incurred from Schedules 1-A3 and 1-A4 of this Tariff.

E. For Resources that are not ESRs, opportunity cost shall be an estimate of the Energy and Operating Reserve Markets revenues net of short run marginal costs for the marginal forgone run time during the timeframe when the Resource experiences the run-time restrictions as detailed in the Market Protocols. The run-time restrictions shall be updated as specified in the Market Protocols, with more frequent updating to occur the fewer hours that remain available, consistent with the Market Protocols. The Market Participant may include in the calculation of its mitigated Energy Offer Curve an amount reflecting the resource-specific opportunity costs expected to be incurred under the following circumstances:

(1) Externally imposed environmental run-hour restrictions; or
(2) Physical equipment limitations on the number of starts or run-hours, as verified by the Market Monitoring Unit and determined by reference to the manufacturer’s recommendation or bulletin, or a documented restriction imposed by the applicable insurance carrier; or
(3) Fuel Supply Limitations.

Resource specific opportunity costs are calculated by forecasting Locational Marginal Prices based on futures contract prices for natural gas and the historical relationship between the SPP system marginal Energy component of LMP and the price of natural gas, as determined by the SPP Market Monitoring Unit. The formulas and instructions in the price
forecast model shall be determined by the SPP Market Monitoring Unit and published in the Market Protocols as part of the Mitigated Offer Development Guidelines, updated, as needed, by the SPP Market Monitoring Unit. Such forecasts of LMPs shall take into account historical variability, and basis differentials affecting the Settlement Location at which the Resource is located for the three-year period immediately preceding the period of time in which the Resource is bound by the referenced restrictions, and shall subtract therefrom the forecasted costs to generate energy at the Settlement Location at which the Resource is located, as specified in more detail in Appendix G of the Market Protocols. If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative, the resulting opportunity cost shall be zero. The Market Monitoring Unit will verify all Market Participants’ opportunity cost calculations for consistency and accuracy. When the Market Monitoring Unit determines that the market price for any period was not competitive, it will adjust the LMP forecasting process used in the opportunity cost calculations to ensure that forecasted LMPs do not reflect non-competitive market conditions.

The following formula shall apply to all mitigated Energy Offer Curves unless specified otherwise in this Section 3.2(E) of this Attachment AF:

\[
\text{Mitigated Energy Offer ($/MWh) = HeatRate (mmBtu/MWh) \times Performance Factor \times Total Fuel Related Costs ($/mmBtu) + EOC VOM ($/MWh) + Opportunity Costs ($/MWh) + Schedule 1-A3 Charge ($/MWh) + Schedule 1-A4 Charge ($/MWh)}
\]

F. The Market Participant shall submit heat rate curves, descriptions of how spot fuel prices and/or contract prices are used to calculate fuel costs, variable fuel transportation and handling costs, emissions costs, and VOM to the Market Monitoring Unit. All cost data and cost calculation descriptions are subject to the review and approval of the SPP Market Monitoring Unit to ensure reasonableness and consistency across Market Participants. The information will be sufficient for replication of the
mitigated Energy Offer Curve and shall include, among other data, the following information:

(1) For fuel costs, Market Participants shall provide the Market Monitoring Unit with an explanation of the Market Participants’ fuel cost policy, indicating whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or referenced spot market prices. Any included fuel transportation and handling costs must be short-run marginal costs only, exclusive of fixed costs.

(2) For emissions costs, Market Participants shall report the emissions rate of each of their units and indicate the applicable emissions allowance cost.

(3) For VOM costs, Market Participants shall submit VOM costs, calculated in adherence with the Appendix G of the Market Protocols, reflecting short-run marginal costs, exclusive of fixed costs.

Further details associated with the development, validation, and updating of these costs are included in Appendix G of the Market Protocols.

G. For Demand Response Resources utilizing Behind-The-Meter Generation, the mitigated Energy Offer Curve shall be developed in the same manner as any other generating Resource as described above. For Demand Response Resources utilizing load reduction, the mitigated Energy Offer Curve shall reflect the quantifiable opportunity costs associated with the reduction, net of related offsetting increases in usage.

H. For Dispatchable Variable Energy Resources, the mitigated Energy Offer Curve may include, but shall not exceed, any quantifiable costs that vary by MWh output, including short-run incremental VOM. Mitigation will not apply to Non-Dispatchable Variable Energy Resources in the Real-Time Balancing Market; monitoring of Energy Offers for Non-Dispatchable Variable Energy Resources will occur.
I. For an ESR, the mitigated Energy Offer Curve may include, but shall not exceed, (i) charging cost and (ii) opportunity cost, both adjusted for round-trip efficiency. Charging cost is the cost at which the ESR charged, and opportunity cost is the average profit in the next hour forgone by charging or discharging in the current hour. The sum of the charging cost and opportunity cost is the average LMP that is expected for the next Operating Hour. This expected average LMP for the next Operating Hour is the unweighted average of the LMPs for the most recent 45 days comparing like Operating Hours. The mitigated Energy Offer Curve for MSRs shall have at least two breakpoints: one for charging and another for discharging. More breakpoints may be added to the extent that other costs vary.

The following formula shall apply to mitigated Energy Offer Curves for ESRs:

\[
\text{Charging Mitigated Energy Offer} (\$/\text{MWh}) = \text{Performance Factor} \times \text{Average LMP Expected for the Next Hour} (\$/\text{mmBtu}) \times \text{Round-Trip Efficiency - EOC VOM} (\$/\text{MWh})
\]

\[
\text{Discharging Mitigated Energy Offer} (\$/\text{MWh}) = \text{Performance Factor} \times \text{Average LMP Expected for the Next Hour} (\$/\text{mmBtu}) / \text{Round-Trip Efficiency + EOC VOM} (\$/\text{MWh})
\]

J. Intra-day changes to the mitigated Energy Offer Curve are allowed under the following conditions:

(1) In the event that the Transmission Provider requests that a Resource remain online past their commitment period by the Day-Ahead Market or a RUC process, the Market Participant may submit an updated mitigated Energy Offer Curve that reflects the procurement of higher cost fuel;

(2) A Resource must switch fuels due to unforeseen operating conditions; or

(3) The Resource is an ESR.
Intra-day changes to the mitigated Energy Offer Curve must follow the mitigated offer development guidelines in Appendix G of the Market Protocols. Any such changes will be validated by the Market Monitor.

K. A Market Participant that has a Resource with short-run marginal costs greater than the Safety-net Energy Offer Cap specified in Section 4.1.1 of Attachment AE of this Tariff may submit an Energy Offer Curve using the same guidelines for development of the Resource’s Mitigated Energy Offer Curve established in Appendix G of the Market Protocols. The Energy Offer Curve above $1,000/MWh must be equal to the Mitigated Energy Offer Curve and may include an adder with a maximum of $100/MWh due to the uncertainty of expected costs. For purposes of LMP calculation, the Energy Offer Curve will be limited to a maximum of $2,000/MWh and will have to be verified by the Market Monitor prior to the start of the applicable market clearing process. If the Energy Offer Curve cannot be verified prior to the start of the applicable market clearing process, then the Resource may be eligible to receive make-whole payments for its actual costs after verification by the Market Monitor. The default value is $1,000/MWh for any offer above $1,000/MWh until the offer can be verified. If the verified Energy Offer Curve is greater than $2,000/MWh, the Energy Offer Curve will be capped at $2,000/MWh in the applicable market clearing process, and the Resource may be eligible for make-whole payments for actual costs exceeding $2,000/MWh. Market Participants must submit evidence of actual costs to the Market Monitor. The Market Monitor shall verify the actual costs for use in make-whole payments. In order to include the costs in the make-whole payments of the final Settlement Statement, the submission must occur within 35 calendar days after the Operating Day and the verification must be complete no later than noon on the business day prior to 45 calendar days after the Operating Day.

L. In all cases under this Section 3.2, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the
confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

3.3 Mitigation Measures for Start-Up Offers and No-Load Offers
A mitigated Start-Up Offer and a mitigated No-Load Offer shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. The mitigated Start-Up and No-Load Offers may be updated up to the close of the Day-Ahead Market for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the Start-Up and No-Load Offers may be updated until the Day-Ahead RUC begins. The mitigated Start-Up and No-Load Offers submitted at the time the Day-Ahead RUC begins will apply to the Day-Ahead RUC on the day before the Operating Day and the Intra-Day RUC on the Operating Day unless an exception is allowed in Section 3.3(G) of this Attachment AF.

A. For a Resource that was not committed to address a Local Reliability Issue, the Start-Up and No-Load Offer conduct threshold is a 25% increase above the mitigated Start-Up or mitigated No-Load Offer, as applicable.

B. For a Resource that was not committed to address a Local Reliability Issue, the Transmission Provider shall apply mitigation measures by replacing the Start-Up or No-Load Offer with the applicable mitigated Start-Up or No-Load Offer if:

1. The Resource’s Start-Up or No-Load Offer exceeds the mitigated Start-Up or mitigated No-Load Offer, as applicable, by the applicable conduct threshold; and

2. The Resource has local market power as determined in Sections 3.1(1) or 3.1(2); and

3. The Resource either:
   (a) Fails the Market Impact Test as described in Section 3.7, or
   (b) Is manually committed by the Transmission Provider or by a local transmission operator.
C. For a Resource that has local market power as determined in Section 3.1(3), the Transmission Provider shall apply mitigation measures by placing a cap on the Start-Up Offer or No-Load Offer of 10% above the mitigated Start-Up Offer or No-Load Offer, as applicable.

D. The mitigated Start-Up Offer shall represent the cost per start as determined from start fuel usage and the costs related to that fuel usage, Performance Factor, cost of electricity for station use to start (“Station Service”), start-up VOM cost, start major maintenance cost, and start additional labor costs, if required above normal station staffing levels. Further guidelines for the mitigated Start-Up Offer are documented in Appendix G of the Market Protocols. The mitigated Start-Up Offer for Demand Response resources shall be the cost to shut down or curtail load for a given period, which varies with the number of deployments rather than the amount of response, and/or the start cost of Behind-The-Meter Generation utilizing the mitigated Start-Up Offer calculation applicable to other generation Resources as defined above.

The mitigated Start-Up Offer for Variable Energy Resources shall be zero.

E. The mitigated No-Load Offer shall be the hourly fixed cost, represented in $/hr, required to operate the Resource at zero electricity output to the grid. The mitigated No-Load Offer can be calculated using either (1) the no-load fuel approach that includes no-load fuel (mmBtu/hour), Performance Factor, no-load VOM cost ($/mmBtu), total fuel related cost ($/mmBtu), and no-load major maintenance cost ($/hr); or (2) calculated using the no-load cost approach that includes heat input at Minimum Economic Capacity Operating Limit (mmBtu), Performance Factor, total fuel related cost ($/mmBtu), no-load VOM cost ($/mmBtu), incremental cost up to Minimum Economic Capacity Operating Limit ($/MWh), Minimum Economic Capacity Operating Limit (MW), and no-load major maintenance cost ($/hr). Further guidelines for the mitigated No-Load Offer are documented in Appendix G of the Market Protocols.
The mitigated No-Load Offer for Demand Response Resources utilizing Behind-The-Meter Generation shall adhere to the same definition above as a generating Resource. For Demand Response Resources utilizing load reduction, the mitigated No-Load Offer shall not exceed the quantifiable ongoing hourly costs associated with load reduction. The mitigated No-Load Offer for Variable Energy Resources shall be zero.

F. The Market Participant shall submit all inputs used in calculating mitigated Start-Up and mitigated No-Load Offers to permit the Market Monitor to verify submitted offers. Required information includes: heat rate curves, descriptions of how spot fuel prices and/or contract prices are used to calculate fuel costs, variable fuel transportation and handling costs, emissions costs, and VOM cost. All cost data and cost calculation descriptions are subject to the review and approval of the SPP Market Monitoring Unit to ensure reasonableness and consistency across Market Participants. Information to be provided by the Market Participant shall include the following:

1. For fuel costs, Market Participants shall provide the Market Monitoring Unit with an explanation of the Market Participants’ fuel cost policy, indicating whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or referenced spot market prices. Any included fuel transportation and handling costs must be short-run marginal costs only, exclusive of fixed costs.

2. For emissions costs, Market Participants shall report the emissions rate of each of their units and indicate the applicable emissions allowance cost.

3. For VOM costs, Market Participants shall submit VOM costs reflecting short-run marginal costs, exclusive of fixed costs.

4. For start and no-load major maintenance cost, Market Participants may include these costs as a component of the mitigated Start-Up
Offer and the mitigated No-Load Offer. Such cost must be based solely on resource-specific information derived from actual variable maintenance costs, when available, or estimated variable maintenance costs. The maintenance period for start major Maintenance cost must be tied to the number of starts, and the maintenance period for no-load major maintenance cost must be tied to the number of Resource run hours.

Further details associated with the development, validation and updating of these costs are included in Appendix G of the Market Protocols.

G. Intra-day changes to the mitigated Start-Up and mitigated No-Load Offers are allowed under the following conditions:

(1) In the event that the Transmission Provider requests that a Resource remain online past their commitment period, the Market Participant may submit updated mitigated Start-Up and mitigated No-Load Offers that reflect the procurement of higher cost fuel;

(2) A Resource must switch fuels due to unforeseen operating conditions; or

(3) The Resource is an ESR.

Intra-day changes to the mitigated Start-Up and mitigated No-Load offers must follow the mitigated offer development guidelines Appendix G of in the Market Protocols. Any such changes will be validated by the Market Monitor.

H. In all cases under this Section 3.3, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

3.3.1 Mitigation Measures for Transition State Offers

The mitigation measures in this section apply only to MCRs. A mitigated Transition State Offer shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines specified in the Market Protocols for each potential transition state changes. The
mitigated Transition State offer may be updated up to the close of the Day-Ahead Market before the Operating Day as defined in Section 5.1 of Attachment AE of this Tariff for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Transition State Offer may be updated until the Day-Ahead RUC process begins. The mitigated Transition State Offer submitted at the time the Day-Ahead RUC process begins will apply to the Day-Ahead RUC process on the day before the Operating Day and Intra-Day RUC processes on the Operating Day.

A. For an MCR that was not transitioned to address a Local Reliability Issue, the Transition State Offer conduct threshold is a 25% increase above the mitigated Transition State Offer.

B. For an MCR that was not transitioned to address a Local Reliability Issue, the Transmission Provider shall apply mitigation measures by replacing the Transition State Offer with the mitigated Transition State Offer if:

1. The Resource’s Transition State Offer exceeds the mitigated Transition State Offer by the applicable conduct threshold; and
2. The Resource has local market power as determined in Sections 3.1(1) or 3.1(2); and
3. The Resource either:
   a. Fails the Market Impact Test as described in Section 3.7, or
   b. Is manually committed by the Transmission Provider or by a local transmission operator.

C. For an MCR that has local market power as determined in Section 3.1(3), the Transmission Provider shall apply mitigation measures by placing a cap on the Transition State Offer of 10% above the mitigated Transition State Offer.
D. The mitigated Transition State Offer for an MCR shall represent the costs of moving from the current configuration to another configuration as determined from the fuel costs incurred during the transition, the costs related to that fuel usage, Performance Factor, and additional maintenance and labor costs incurred during the transition, including transition VOM cost and transition major maintenance cost. Further guidelines for the mitigated Transition State Offer are documented in Appendix G of the Market Protocols.

The Market Participant shall submit documentation of the method and any cost data for calculating the mitigated Transition State Offer that is necessary to allow the Market Monitor to validate submitted offers. Further details associated with the development of these costs are included in the Market Protocols.

E. Intra-day changes to the mitigated Transition State Offers are allowed under the following conditions:

(1) In the event that the Transmission Provider requests that a Resource remain online past their commitment period, the Market Participant may submit an updated mitigated Transition State Offer that reflects the procurement of higher cost fuel; or

(2) A Resource must switch fuels due to unforeseen operating conditions.

Intra-day changes to the mitigated Transition State Offers must follow the mitigated offer development guidelines in Appendix G of the Market Protocols. Any such changes will be validated by the Market Monitor.

F. In all cases under this Section 3.3.1, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of the Tariff.
3.4 Mitigation Measures for Operating Reserve Offers

A mitigated offer for each Operating Reserve product shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. For MCRs for which a single configuration allows physical units to be swapped (e.g., Combustion Turbine 2 for Combustion Turbine 1), the costs used in the mitigated offer development for that configuration shall be those of the least cost physical unit that is available and can be swapped in such configuration. The mitigated Operating Reserve Offers may be updated up to the close of the Day-Ahead Market for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Operating Reserve Offers may be updated until the Day-Ahead RUC begins. For Resources committed by the Day-Ahead Market, the mitigated Operating Reserve Offers submitted as of the close of the Day-Ahead Market will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day unless an exception is allowed in Section 3.4(I) of this Attachment AF; for all other Resources, the mitigated Operating Reserve Offers submitted at the time the Day-Ahead RUC begins will apply to the RTBM on the Operating Day.

A. For a Resource with an Operating Reserve Offer greater than or equal to $10/MWh that was not committed to address a Local Reliability Issue, the offer conduct threshold for each of the Operating Reserve products is a 25% increase above the mitigated offer for the applicable Operating Reserve Offer.

B. For a Resource with an Operating Reserve Offer greater than or equal to $10/MWh that was not committed to address a Local Reliability Issue, the Transmission Provider shall apply mitigation measures by replacing the Operating Reserve Offer with the applicable mitigated Operating Reserve Offer if:

(1) The Resource’s Operating Reserve Offer exceeds the applicable mitigated offer by the conduct threshold; and
(2) The Resource has local market power as determined in Sections 3.1(1) or 3.1(2); and

(3) The Resource either:
   (a) Fails the Market Impact Test as described in Section 3.7, or
   (b) Is manually committed by the Transmission Provider or by a local transmission operator.

A Resource with an Operating Reserve Offer below $10/MWh shall not be subject to mitigation measures on its applicable Operating Reserve Offer for economic withholding.

C. For a Resource with an Operating Reserve Offer greater than or equal to $10/MWh that has local market power as determined in Section 3.1(3), the Transmission Provider shall apply mitigation measures by placing a cap on the Operating Reserve Offer of 10% above the applicable mitigated Operating Reserve Offer. A Resource with an Operating Reserve Offer below $10/MWh shall not be subject to mitigation measures on its applicable Operating Reserve Offer for economic withholding.

D. The mitigated Spinning Reserve Offer shall be equal to zero for Resources other than combustion turbines, reciprocating engines and hydro Resources operating as a synchronous condenser. No known incremental costs are incurred for providing Spinning Reserves from other resource types.

Total mitigated Spinning Reserve Offer for combustion turbines, reciprocating engines and hydro Resources operating as a synchronous condenser shall not exceed any additional fuel related costs, maintenance costs and power consumption costs necessary for the Resource to be prepared for deployment of Spinning Reserve:

\[
\text{Mitigated Spinning Reserve Offer ($/MW)} \leq \\
(\text{Additional Fuel Cost($/Hr)} + \text{Additional Maintenance Cost ($/Hr)} + \text{Condensing Power Cost ($/Hr)}) / \\
\text{Spinning Reserve MW}
\]
The mitigated Supplemental Reserve Offer shall not exceed labor costs necessary for the Resource to be prepared for deployment of Supplemental Reserve:

Mitigated Supplemental Reserve Offer ($/MW) ≤ Additional Labor Cost($) / Average Supplemental Reserve MW

E. The mitigated Regulation-Up Service Offer shall not exceed the sum of the cost increase due to:

1. the heat rate increase during non-steady state operation,
2. increase in VOM due to non-steady state operation,
3. uncompensated costs, as described in the Market Protocols:

Where:

Mitigated Regulation-Up Service Offer = Mitigated Regulation-Up Offer ($/MW) + Mitigated Regulation-Up Mileage Offer ($/MW),

Mitigated Regulation-Up Offer ($/MW) ≤ Uncompensated Cost ($/MW), and

Mitigated Regulation-Up Mileage Offer ($/MW) ≤ (Cost Increase due to a decreased energy conversion efficiency (e.g., Heat Rate Increase) during non-steady state operation + Cost Increase in VOM) * Regulation-Up Mileage Factor

F. The mitigated Regulation-Down Service Offer shall not exceed the sum of the cost increase due to:

1. the heat rate increase during non-steady state operation,
2. increase in VOM due to non-steady state operation,
3. uncompensated costs, as described in the Market Protocols:

Where:

Mitigated Regulation-Down Service Offer = Mitigated Regulation-Down Offer ($/MW) + Mitigated Regulation-Down Mileage Offer ($/MW),

Mitigated Regulation-Down Offer ($/MW) ≤ Uncompensated Cost ($/MW), and
Mitigated Regulation-Down Mileage Offer ($/MW) ≤
(Cost Increase due to a decreased energy conversion efficiency (e.g., Heat Rate Increase) during non-steady state operation + Cost Increase in VOM) * Regulation-Down Mileage Factor

Further details associated with the development of the exact costs in the formulas above are included in the Market Protocols.

G. Ramp Capability Up, Ramp Capability Down, and online Uncertainty Reserve products will not require mitigated offers, as the cost of these products shall be the marginal cost of lost opportunity and not participant Offers.

H. The mitigated offline Uncertainty Reserve Offers shall not exceed the costs that shall not be eligible for reimbursement through a make whole payment for Resources that clear offline Uncertainty Reserve, and are committed to provide energy as a result of that clearing, as described in Section 8.6.5 of Attachment AE of this Tariff. These costs shall be amortized over the Resource’s expected Uncertainty Reserve megawatts and Uncertainty Reserve response time:

\[
\text{Offline Uncertainty Reserve ($/MWh) =}
\]

\[
\left(\text{Start-Up Costs ($/Start)} + \text{No-Load Costs ($/hour)\cdot \max(\text{Uncertainty Reserve response time, Minimum Run Time) (hours) + Minimum Energy Costs during the larger of the Uncertainty Reserve response time and Minimum Run Time ($/Start)})} \right) / (\text{Expected Uncertainty Megawatts } \cdot \text{Uncertainty Reserve response time (hours)}))
\]

Expected uncertainty megawatts are derived from the total rampable capacity that an offline resource can provide, from an offline state, during the Uncertainty Reserve response time. This includes the ramp provided to reach the Minimum Economic Capacity Operating Limit, plus any ramp that can be provided to the market during the remaining Uncertainty Reserve response time. For example, if a Resource has a 60 MWh ramp rate, a Minimum Economic Capacity Operating Limit of 20 megawatts, a Maximum Economic Capacity Operating Limit of 100 megawatts, and a combined Start-Up Time and Sync-To-Min Time of 40 minutes, then the expected Uncertainty Reserve megawatts will be 40 megawatts when the
Uncertainty Reserve response time is one hour. In this example, 20 megawatts came from the Resource reaching its economic minimum limit, then 20 megawatts came from the 20 minutes remaining in the Uncertainty Reserve response time [1 hour response time -( Start-Up Time+ Sync-to-min)] multiplied by the one megawatt per minute ramp rate.

I. Intra-day changes to the mitigated Operating Reserve Offers are allowed under the following conditions:

1. In the event that the Transmission Provider requests that a Resource that is supplying Operating Reserves remain online past their commitment period by the Day-Ahead Market or a RUC process, the Market Participant may submit an updated mitigated Operating Reserve offer curve that reflects the procurement of higher cost fuel;

2. A Resource must switch fuels due to unforeseen operating conditions; or

3. Intra-day changes to the mitigated Regulation-Up and mitigated Regulation-Down Offers are allowed after the Day-Ahead RUC clears on the day before the Operating Day under the following condition:

   a. The Resource incurs the uncompensated cost in Section 3.4(E)(3) of this Attachment AF, for which the mitigated offer calculation is described in Appendix G of the Market Protocols.

Intra-day changes to the mitigated Operating Reserve Offer curve must follow the mitigated offer development guidelines in Appendix G and Section 8.2.2 of the Market Protocols. Any such changes will be validated by the Market Monitor.

J. The Market Participant may include in the calculation of its mitigated Operating Reserve Offer an amount reflecting the Resource-specific opportunity costs if the Market Participant is able to demonstrate to the satisfaction of the SPP Market Monitoring Unit that such costs are legitimate and verifiable and not otherwise included in market outcomes. To the extent such costs include run-time restrictions, such run-time restrictions shall be updated as specified in the Market Protocols, with more frequent updating to occur the fewer hours that remain available,
consistent with the Market Protocols. The formulas and instructions in the price forecast model for any such opportunity costs shall be determined by the SPP Market Monitoring Unit and published in the Market Protocols as part of the Mitigated Offer Development Guidelines, updated, as needed, by the SPP Market Monitoring Unit. Opportunity costs for mitigated Operating Reserve Offers shall not include Energy and Operating Reserve Markets revenues associated with forgone Energy or other types of Operating Reserve production to the extent that such costs are included in market outcomes.

K. All cost data and cost calculation descriptions are subject to the review and approval of the SPP Market Monitoring Unit to ensure reasonableness and consistency across Market Participants. The information will be sufficient for replication of the mitigated Operating Reserve Offers and shall include, among other data, the following information:

(1) For fuel costs, Market Participants shall provide the Market Monitoring Unit with an explanation of the Market Participants’ fuel cost policy, indicating whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or referenced spot market prices. Any included fuel transportation and handling costs must be short-run marginal costs only, exclusive of fixed costs.

(2) For emissions costs, Market Participants shall report the emissions rate of each of their units and indicate the applicable emissions allowance cost.

(3) For VOM costs, Market Participants shall submit VOM costs, calculated in adherence with the Appendix G of the Market Protocols, reflecting short-run marginal costs, exclusive of fixed costs.

L. In all cases under this Section 3.4, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.
3.5 Validation of Mitigated Resource Offer Parameters

The Market Monitor shall review the costs included in each mitigated Resource Offer on an ex-post basis relative to the relevant Operating Day in order to ensure that the Market Participant has correctly applied the formulas and definitions in Sections 3.2, 3.3.1, and 3.4 of this Attachment AF and in the Market Protocols and that the level of the mitigated offer is otherwise acceptable. If the mitigated offer determined by the Market Monitor and the Market Participant differ, Market Participant shall use the mitigated offer calculated by the Market Monitor going forward. If a Market Participant submits a dispute over its mitigated offer, the previously approved mitigated offer shall be used from the time the dispute is submitted until the dispute is resolved. The procedures for submitting and processing disputes related to mitigated offers shall be those specified in the Market Protocols. The Transmission Provider shall remedy mitigated offer disputes resolved in favor of the Market Participant by providing make whole payments, as necessary, to the Market Participant whose mitigated offer was improperly determined by the Market Monitor.

Each Market Participant is obligated to provide to the Market Monitor any cost data necessary to allow the Market Monitor to validate its mitigated Resource Offer.

The Market Monitor shall keep such data confidential, and all cost data submitted under this Section 3.5, including any opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff. The Market Monitor shall develop and maintain on the Transmission Provider’s website the mechanism and procedures to allow Market Participants to submit such cost data.

3.6 Additional Mitigation Measures for Resource Offer Parameters

The mitigation measures in this section apply to all Resource Offer parameters expressed in units other than dollars and will only apply in the presence of local market power as described in Section 3.1 of this Attachment AF. A reference level for each applicable Resource Offer parameter that reflects the physical capability of the Resource shall be determined prior to the start of the Energy and Operating Reserve Markets by one or both of the following methods: (i) the reference levels will be determined through consultation between the Market Participant and the Market Monitor; and/or (ii) the
reference levels will be based on averages of Resource Offer parameters from similar Resources. This methodology for setting reference levels for Offer parameters shall apply to all Resources at the start of the Energy and Operating Reserve Markets and to all Resources that register subsequent to the start of the Energy and Operating Reserve Markets. The Transmission Provider’s output forecast for a wind-powered Variable Energy Resource shall be used as the reference maximum output limit for the wind-powered Variable Energy Resource.

The following thresholds shall be used by the Transmission Provider to identify Resource Offers that may warrant mitigation and shall be determined with respect to the corresponding reference level:

Time-based Resource Offer parameters: An increase of three (3) hours, or an increase of six (6) hours in total for multiple time-based Resource Offer parameters.

Resource Offer parameters expressed in units other than time or dollars: One hundred percent (100%) increase for Resource Offer parameters that are minimum values, or a fifty percent (50%) decrease for Resource Offer parameters that are maximum values.

Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Maximum Charge Limit, as applicable, threshold for Resources committed to address a Local Reliability Issue: twenty-five percent (25%) increase.

Maximum Charge Limit, as applicable, threshold for Resources committed to address a Local Reliability Issue: twenty-five percent (25%) decrease.

In the case that a Resource Offer fails the thresholds described above, the Market Monitor shall determine the impact on prices or make whole payments. If an impact exceeds the LMP, MCP or make whole payment thresholds in Section 3.7, the Market Monitor will initiate a discussion with the Market Participant concerning an explanation of the parameter changes. The Market Monitor will inform the Transmission Provider of any potential issue. If the Transmission Provider, in consultation with the Market Monitor, concludes that the Market Participant has demonstrated the validity of the submitted Resource Offer parameter, no further action will be taken. If not, the
 Transmission Provider shall replace the Resource Offer parameter with the corresponding reference level. Mitigation measures will remain in place until such time that the Market Participant demonstrates the validity of the Resource Offer parameter or the Market Participant notifies the Market Monitor that the Resource Offer parameter has been changed to a value that is within the tolerance range as described above, and the Market Monitor has verified that this change has occurred. In the event that the Market Participant submits a dispute, the mitigation measure will remain in place until the resolution of the dispute.

In all cases under this Section 3.6, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

3.7 Market Impact Test

The Transmission Provider will apply the following market impact test in the Day-Ahead Market, Day-Ahead RUC, Intra-Day RUC and Real-Time Balancing Market in the event the conditions described in Section 3.1 of this Attachment AF are satisfied:

After an initial market solution is computed with no mitigation measures in place, a second market solution, called the mitigated market solution, will be computed with the appropriate mitigation measures applied. With the exception of Ramp Capability Up and Ramp Capability Down, if an LMP or MCP at a Settlement Location from the initial market solution exceeds the corresponding price from the mitigated market solution by the applicable impact test threshold, or a make whole payment for any Resource from the initial market solution exceeds the corresponding make whole payment from the mitigated market solution by make whole payment impact test threshold, then the mitigated market solution will be used for dispatch, commitment, and settlement purposes.

The LMP impact threshold is twenty-five dollars ($25) per megawatt hour, the MCP impact threshold is twenty-five dollars ($25) per megawatt hour, and the make whole payment impact threshold is twenty-five dollars ($25) per megawatt hour.

3.8 Mitigation Exceptions
A. The Market Monitor shall, as soon as practicable and if warranted in light of the information available to the Market Monitor, contact a Market Participant to request an explanation of its actions in cases when an impact threshold in Section 3.7 of this Attachment AF is exceeded and the Market Participant’s offer exceeded the mitigated offer by more than the applicable conduct threshold, as specified in Section 3.2, 3.3, 3.3.1, or 3.4 of this Attachment AF.

3.9 Sanctions for Noncompliance with the Day-Ahead Market Must Offer Requirement

A. In the case that a Market Participant is found to be noncompliant for an Asset Owner as determined by the conditions set forth in Section 2.11.1 of Attachment AE, the Market Participant shall be assessed a penalty for that Asset Owner by the Transmission Provider for each megawatt of withheld capacity below the 10% tolerance band. The penalty amount shall be equal to the Day-Ahead Market LMP associated with the withheld capacity.

B. The Market Monitor will monitor for, and report to the Commission’s Office of Enforcement, or its successor organization, manipulative behavior associated with Day-Ahead Offers, including (but not limited to) monitoring load-serving Market Participants who do not offer enough net resource capacity to meet their maximum hourly Reported Load. The Market Monitor will also report to the Commission’s Office of Enforcement or its successor organization any locational problems, such as deliverability issues, associated with load-serving Market Participants’ offers in the Day-Ahead Market, any identified efforts by Market Participants to raise prices in the RTBM by limiting Day-Ahead Offers, and the effects of any such efforts upon make whole payments.
ADDENDUM 1 TO ATTACHMENT AO

AGREEMENT ESTABLISHING A PSEUDO-TIE ELECTRICAL INTERCONNECTION POINT WHERE THERE IS NO APPLICABLE JOINT OPERATING AGREEMENT WITH AN EXTERNAL BALANCING AUTHORITY

This Agreement Establishing a Pseudo-Tie Electrical Interconnection Point (including its exhibits, this “Agreement”) is entered into this ___ day of __________ 20___ by and among __________ (“External Balancing Authority”), ______________ (“Market Participant”), and the Southwest Power Pool, Inc. (“SPP”). External Balancing Authority, Market Participant and SPP are hereinafter referred to individually as a “Party” and collectively as the “Parties.”

WHEREAS, in order to facilitate the foregoing, the Parties desire to establish a new pseudo-tie electrical interconnection point between the SPP Balancing Authority and the External Balancing Authority on the terms and conditions set forth in this Agreement; and

WHEREAS, there are no terms or conditions in a joint operating agreement or any other agreement that specifies the coordination between the SPP Balancing Authority and the External Balancing Authority for pseudo-tie electrical interconnection points between the SPP Balancing Authority and the External Balancing Authority; and

WHEREAS, SPP is a Regional Transmission Organization approved by the Federal Energy Regulatory Commission operating an Integrated Marketplace and is a NERC certified Balancing Authority; and

WHEREAS, the External Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant to the SPP Balancing Authority as defined below or the External Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined below; and

WHEREAS, the Market Participant is responsible for generation or load outside of the boundaries of the SPP Balancing Authority Area and desires to participate in the Integrated Marketplace as a Resource or load or the Market Participant is responsible for generation or load inside the SPP Balancing Authority Area and desires not to participate in the Integrated Marketplace; and

WHEREAS, the SPP Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant from the External Balancing Authority as defined below or the SPP Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined below; and
WHEREAS, Market Participant represents the generator or load serving entity that is physically located within the balancing authority boundaries of the External Balancing Authority or the SPP Balancing Authority; and

WHEREAS, Market Participant represents the generator or load serving entity registered with SPP and meeting all of the SPP qualifications in order to operate in the Integrated Marketplace and abiding by all the respective Market Protocols and rules as set forth by SPP.

NOW THEREFORE, in consideration of the mutual covenants and agreements in this Agreement and of other good and valuable consideration, the sufficiency and adequacy of which are hereby acknowledged, the Parties, intending to be legally bound, hereby agree as follows:

1. **Creation of Pseudo-Tie Point.** From and after the effective date hereof, the point at which pseudo-tie electrical interconnection is made between the Market Participant ____________ (Name of the generation or load) ____________ (generation or load location) (the “Facility”) and the SPP Balancing Authority, which shall be defined in the one-line diagram attached hereto as Exhibit A, shall be a new pseudo-tie electrical interconnection point between the SPP Balancing Authority and the External Balancing Authority (the “Pseudo-Tie Point”), whereby any energy delivered from or consumed by the Facility at the Pseudo-Tie Point shall be treated as a balancing authority interchange between the External Balancing Authority and the SPP Balancing Authority (for the avoidance of doubt, whether or not, at the time of delivery or consumption of such energy, the metering, data processing, telemetry and other equipment associated with the Pseudo-Tie Point is properly functioning). For the avoidance of doubt, the SPP Balancing Authority or the External Balancing Authority will not be taking title to any energy delivered from or consumed by the Facility at the Pseudo-Tie Point.

2. **Implementation.** Each Party shall design, construct, operate and maintain the equipment for which it is responsible under this Agreement, and shall take all other actions required of it, to create and have the Pseudo-Tie Point recognized by the SPP as a balancing authority interchange between the External Balancing Authority and the SPP Balancing Authority for the purpose of allowing the Facility to be treated as being in the SPP Balancing Authority or the External Balancing Authority. Without limiting the foregoing, each Party shall undertake the design, construction, operation and maintenance for which it is responsible under this Agreement according to North American Electric Reliability Corporation standards. A basic block diagram of the communications equipment required for the Pseudo-Tie Point is set forth in Exhibit B. As among the Parties:

(a) The entity representing the generator or load in the External Balancing Authority or the generator or load within the SPP Balancing Authority shall register with SPP to become a Market Participant in the Integrated Marketplace. Registration shall be done in accordance with the SPP Market Protocols. Each Facility must be registered separately with SPP and registration information shall be provided to the External Balancing Authority. Market Participant must register its generator or load located in the External Balancing Authority or its generator or load located in the SPP Balancing Authority.
(b) This Agreement does not provide for the reservation or sale of transmission service under the SPP’s Open Access Transmission Tariff or on any other transmission system. Market Participant shall secure and pay for all cost associated with transmission service, across all transmission service providers necessary to deliver or consume power from the Facility to the interface point with the SPP Balancing Authority or to the interface point with the External Balancing Authority.

(c) In order to supply Energy and qualified Operating Reserve products (Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, Ramp Capability Down, and/or Uncertainty Reserve) to the Integrated Marketplace or to transfer load to the Integrated Marketplace, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the SPP Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting participation and for continued participation in the Energy and Operating Reserve Markets.

(d) In order to supply energy to the External Balancing Authority or to transfer load to the External Balancing Authority, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the External Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting approval of the movement of Resources and load out of the SPP Balancing Authority to the External Balancing Authority.

(e) Market Participant is solely responsible for all requirements as set forth for a Market Participant in the Market Protocols.

(f) Market Participant shall design, construct, operate and maintain systems and communications equipment in order to: (i) receive SPP deployment instructions for generators pseudo-tying into the SPP Balancing Authority; (ii) account for load pseudo-tying into the SPP Balancing Authority; and (iii) enable SPP to account for congestion and losses associated with generators and loads pseudo-tying out of the SPP Balancing Authority in accordance with the Market Protocols.

(g) Market Participant shall design, construct, operate and maintain real-time and historical systems and communications equipment, at Market Participant’s expense, in order to provide the External Balancing Authority and the SPP Balancing Authority with the corresponding real-time pseudo-tie value. Market Participant’s systems shall provide this signal to the SPP Balancing Authority per the SPP Balancing Authority’s ICCP communication standards. Market Participant’s system shall provide this signal to the External Balancing Authority in a manner mutually agreed to between the External Balancing Authority and the Market Participant.

(h) SPP, in accordance with the Market Protocols, will provide the Market Participant commitment and dispatch instructions for generators pseudo-tying into the SPP
Balancing Authority for participation in the Energy and Operating Reserve Markets consistent with such instructions issued to other registered Resources.

(i) For generators pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.

(j) For generators pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(k) For loads pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.

(l) For loads pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(m) The External Balancing Authority and the SPP Balancing Authority will include the real time pseudo-tie value in their respective calculations of Net Actual Interchange and Area Control Error.

(n) If communication is lost between any of the Parties (including communication between SPP and the Market Participant), the External Balancing Authority and the SPP Balancing Authority will freeze at the last known value and it is the responsibility of the Market Participant to verbally communicate changes of the real time pseudo-tie values with the other Parties.

(o) Market Participant shall notify the other Parties of any real-time circumstances that affect the Market Participant’s obligation or ability to meet the SPP Setpoint Instructions or External Balancing Authority instructions. A generator pseudo-tying into the SPP Balancing Authority will be subject to the same penalties as a Resource under Attachment AE of the SPP Tariff. A generator pseudo-tying out of the SPP Balancing Authority will be subject to the rules and procedures specified by the External Balancing Authority.

(p) The External Balancing Authority and the SPP Balancing Authority shall integrate the real time pseudo-tie value on an hourly basis and maintain this information for balancing authority checkout, inadvertent calculations and payback purposes in accordance with the applicable NERC standards. For generators and loads pseudo-tying into the SPP Balancing Authority, it is the responsibility of the External
Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the External Balancing Authority’s final daily checkout with the SPP Balancing Authority. For generators and loads pseudo-tying out of the SPP Balancing Authority, it is the responsibility of the SPP Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the SPP Balancing Authority’s final daily checkout with the External Balancing Authority.

(q) The Market Participant for generators and loads pseudo-tying into or out of the SPP Balancing Authority Area is responsible for submission of settlement meter data for use in the settlement process of the Real-Time Balancing Market in accordance with the SPP Market Protocols.

(r) Except as otherwise provided in this Section 2, failure by the Market Participant to provide real-time pseudo-tie values in a timely manner constitutes a basis for the immediate suspension of this Agreement by the External Balancing Authority or the SPP Balancing Authority. In the event of such suspension, the Market Participant shall provide a remedy for the cause of the failure prior to resumption of participation. In the event of two suspensions within a thirty day period, this Agreement may be terminated, in accordance with Section 7 of this Agreement, at the sole discretion of the External Balancing Authority or the SPP Balancing Authority.

3. **Losses.** For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will be responsible for loss compensation to transmission provider(s) to deliver their energy to or receive their energy from the SPP Balancing Authority. Pseudo-tie value(s) will be considered net of losses external to SPP. Losses within the SPP Balancing Authority attributable to the Market Participant’s participation in the Energy and Operating Reserve Markets, including generators and loads pseudo-tying out of the SPP Balancing Authority, shall be handled in the same manner as other Energy and Operating Reserve Markets transactions.

4. **Compensation.** For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will compensate the External Balancing Authority for the reasonable implementation and operations related costs borne by the External Balancing Authority as a result of this Agreement unless the Market Participant and External Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement. For generators and loads pseudo-tying out of the SPP Balancing Authority, Market Participant will compensate the SPP Balancing Authority for the reasonable implementation and operations related costs borne by the SPP Balancing Authority as a result of this Agreement unless the Market Participant and SPP Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement.

5. **Auditing.** Each Party reserves the right to audit records necessary to permit evaluation and verification of claims submitted, and the other Party’s compliance with this Agreement. The Parties shall retain for a period of three years all information and records relating to the performance of this Agreement. Each Party may examine and copy such information and
records at the other Party’s premises during regular business hours and upon advance notice given no less than 15 calendar days prior to such examination.

6. **Effective Date.** The Agreement is effective upon full execution if it is not filed with the Commission. If the Agreement is filed with the Commission, then it is effective upon the later of the date of execution or the date allowed by the Commission. If the parties are unable to resolve any issues, SPP shall file an unexecuted agreement with the Commission, including all agreed-upon non-conforming deviations.

7. **Termination.** Other than as provided in Section 2(r), this Agreement shall terminate on [Date], unless extended by agreement of all the Parties. Any Party shall have the right to terminate this Agreement upon ___ month’s notice, subject to receiving all necessary regulatory approvals for such termination.

8. **Governing Law.** The interpretation and performance of this Agreement and each of its provisions shall be governed and construed in accordance with the applicable Federal and/or State laws without regard its conflicts of laws provisions that would apply the laws of another jurisdiction.

9. **Interpretation.** In this Agreement:

   (a) the words “include”, “includes” and “including” are deemed to be followed by the words “without limitation”;  

   (b) references to contracts, agreements and other documents and instruments shall be references to the same as amended, supplemented or otherwise modified from time to time;

   (c) references to laws or standards and to terms defined in, and other provisions of, laws or standards shall be references to the same (or a successor to the same) as amended, supplemented or otherwise modified from time to time; and

   (d) references to a person shall include its successors and permitted assigns and, in the case of a governmental or other authority (including SPP and the North American Electric Reliability Corporation), any person succeeding to its functions and capacities.

10. **Severability.** If any provision of this Agreement is held invalid, illegal or unenforceable in any jurisdiction, then, the Parties agree, to the fullest extent permitted by law, that the validity, legality and enforceability of the remaining provisions hereof in such or any other jurisdiction and of such provision in any other jurisdiction shall not in any way be affected or impaired thereby. With respect to the provision held invalid, illegal or unenforceable, the Parties will amend this Agreement as necessary to effect the original intent of the Parties as closely as possible.
11. **Complete Agreement; Amendments.** This Agreement constitutes the entire agreement among the Parties with respect to the subject matter of this Agreement and supersedes other prior agreements and understandings, both written and oral, among the Parties with respect to the subject matter of this Agreement. This Agreement may be amended, supplemented or otherwise modified only by an instrument in writing signed by all Parties.

12. **Other Obligations.** Nothing in this Agreement is intended to modify or change any obligations or rights under any tariff (including the SPP Tariff), any rate schedule, or any other contract. This Agreement does not in any way provide transmission service or address rates, terms or conditions of transmission service or indicate in any way that transmission service is available or properly awarded. A Party seeking transmission service must still go through the full tariff process to obtain transmission service. This Agreement also does not establish any generation as a designated network resource under the Tariff; the requirements of the Tariff still must be satisfied. Nor does this Agreement make any Party a Market Participant under the SPP Tariff. A Party seeking to become a Market Participant must apply to SPP under the terms of the SPP Tariff and nothing in this Agreement affects its rights or obligations as a Market Participant.

13. **Commission Filing.** If unchanged, a signed version of this form agreement shall not be filed with the Commission. SPP will simply report the existence of a signed agreement in its quarterly reports. If the form agreement is substantively changed, then SPP shall file the revised form agreement with the Commission. The Parties shall be bound to the terms accepted or ordered by the Commission.

14. **Modification.** Nothing in this Agreement is intended to modify or limit the right of SPP to submit under FPA Section 205 or Section 206 unilateral changes to this Agreement (both the form Agreement and any signed agreement); the right of any other Party to seek unilateral changes under FPA Section 206, or the right of the Federal Energy Regulatory Commission to accept any FPA Section 205 filing or to make changes under FPA Section 206 or to initiate proceedings under FPA Section 206.

15. **Charges.** The provisions in this Agreement providing for compensation do not authorize Commission regulated public utilities to impose charges without a separately filed tariff or rate schedule being accepted by the Commission.

16. **Disputes.** Any disputes under this Agreement shall first be resolved pursuant to the dispute resolution procedures in the SPP’s Open Access Transmission Tariff. Any disputes may be brought to the Commission.

17. **Breach.** If any Party breaches the terms of this Agreement, then a non-breaching Party may seek any relief it believes is appropriate at the Commission. A breach is considered a substantive violation of this Agreement. Prior to pursuing a remedy at the Commission for a breach, a non-breaching Party shall provide five business days notice of the breach to the breaching Party. If the breaching Party does not eliminate the breach within five (5) business days after the notice is received by the breaching Party, then the non-breaching Party may pursue its remedies at the Commission.
18. **Counterparts.** This Agreement may be executed in one or more counterparts, each of which shall be an original but all of which, taken together, shall constitute only one legal instrument. It shall not be necessary in making proof of this Agreement to produce or account for more than one counterpart. The delivery of an executed counterpart of this Agreement by facsimile shall be deemed to be valid delivery thereof.
The Parties have caused this Agreement to be signed by their authorized representatives on the day and year first above written.

**External Balancing Authority**

By: ___________________________

  Name: _______________________
  Title: _______________________

**SPP Balancing Authority**

By: ___________________________

  Name: _______________________
  Title: _______________________

**Market Participant**

By: ___________________________

  Name: _______________________
  Title: _______________________
ADDENDUM 2 TO ATTACHMENT AO

AGREEMENT ESTABLISHING A PSEUDO-TIE ELECTRICAL INTERCONNECTION POINT WHERE THERE IS AN APPLICABLE JOINT OPERATING AGREEMENT WITH AN EXTERNAL BALANCING AUTHORITY

This Agreement Establishing a Pseudo-Tie Electrical Interconnection Point (including its exhibits, this “Agreement”) is entered into this ____ day of ____________ 20____ between __________________ (“Market Participant”) and the Southwest Power Pool, Inc. (“SPP”). Market Participant and SPP are hereinafter referred to individually as a “Party” and collectively as the “Parties.”

WHEREAS, in order to facilitate the foregoing, the Parties desire to establish a new pseudo-tie electrical interconnection point between the SPP Balancing Authority and __________________ (“External Balancing Authority”) on the terms and conditions set forth in this Agreement; and

WHEREAS, SPP is a Regional Transmission Organization approved by the Federal Energy Regulatory Commission operating an Integrated Marketplace and is a NERC certified Balancing Authority; and

WHEREAS, the External Balancing Authority and the SPP Balancing Authority are parties to the Commission approved SPP - [Name of the External Balancing Authority] Joint Operating Agreement (“JOA”) and the JOA specifies the coordination between the SPP Balancing Authority and the External Balancing Authority for pseudo-tie electrical interconnection points between the SPP Balancing Authority and the External Balancing Authority; and

WHEREAS, the External Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant to the SPP Balancing Authority as defined in the JOA or the External Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined in the JOA; and

WHEREAS, the Market Participant is responsible for generation or load outside of the boundaries of the SPP Balancing Authority Area and desires to participate in the Integrated Marketplace as a Resource or load or the Market Participant is responsible for generation or load inside the SPP Balancing Authority Area and desires not to participate in the Integrated Marketplace; and

WHEREAS, the SPP Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant from the External Balancing Authority as defined in the JOA or the SPP Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined in the JOA; and
WHEREAS, Market Participant represents the generator or load serving entity that is physically located within the balancing authority boundaries of the External Balancing Authority or the SPP Balancing Authority; and

WHEREAS, Market Participant represents the generator or load serving entity registered with SPP and meeting all of the SPP qualifications in order to operate in the Integrated Marketplace and abiding by all the respective Market Protocols and rules as set forth by SPP.

NOW THEREFORE, in consideration of the mutual covenants and agreements in this Agreement and of other good and valuable consideration, the sufficiency and adequacy of which are hereby acknowledged, the Parties, intending to be legally bound, hereby agree as follows:

1. Creation of Pseudo-Tie Point. From and after the effective date hereof, the point at which pseudo-tie electrical interconnection is made between the Market Participant ____________ (Name of the generation or load) ____________ (generation or load location) (the “Facility”) and the SPP Balancing Authority, which shall be defined in the one-line diagram attached hereto as Exhibit A, shall be a new pseudo-tie electrical interconnection point between the SPP Balancing Authority and the External Balancing Authority (the “Pseudo-Tie Point”), whereby any energy delivered from or consumed by the Facility at the Pseudo-Tie Point shall be treated as a balancing authority interchange between the External Balancing Authority and the SPP Balancing Authority (for the avoidance of doubt, whether or not, at the time of delivery or consumption of such energy, the metering, data processing, telemetry and other equipment associated with the Pseudo-Tie Point is properly functioning). For the avoidance of doubt, the SPP Balancing Authority or the External Balancing Authority will not be taking title to any energy delivered from or consumed by the Facility at the Pseudo-Tie Point.

2. Implementation. Each Party shall design, construct, operate and maintain the equipment for which it is responsible under this Agreement, and shall take all other actions required of it, to create and have the Pseudo-Tie Point recognized by the SPP as a balancing authority interchange between the External Balancing Authority and the SPP Balancing Authority for the purpose of allowing the Facility to be treated as being in the SPP Balancing Authority or the External Balancing Authority. Without limiting the foregoing, each Party shall undertake the design, construction, operation and maintenance for which it is responsible under this Agreement according to North American Electric Reliability Corporation standards. A basic block diagram of the communications equipment required for the Pseudo-Tie Point is set forth in Exhibit B. As among the Parties:

(a) The entity representing the generator or load in the External Balancing Authority or the generator or load within the SPP Balancing Authority shall register with SPP to become a Market Participant in the Integrated Marketplace. Registration shall be done in accordance with the SPP Market Protocols. Each Facility must be registered separately with SPP and registration information shall be provided to the External Balancing Authority. Market Participant must register its generator or load located in the External Balancing Authority or its generator or load located in the SPP Balancing Authority.
(b) This Agreement does not provide for the reservation or sale of transmission service under the SPP’s Open Access Transmission Tariff or on any other transmission system. Market Participant shall secure and pay for all cost associated with transmission service, across all transmission service providers necessary to deliver or consume power from the Facility to the interface point with the SPP Balancing Authority or to the interface point with the External Balancing Authority.

(c) In order to supply Energy and qualified Operating Reserve products (Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, Ramp Capability Down, and/or Uncertainty Reserve) to the Integrated Marketplace or to transfer load to the Integrated Marketplace, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the SPP Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting participation and for continued participation in the Energy and Operating Reserve Markets.

(d) In order to supply energy to the External Balancing Authority or to transfer load to the External Balancing Authority, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the External Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting approval of the movement of Resources and load out of the SPP Balancing Authority to the External Balancing Authority.

(e) Market Participant is solely responsible for all requirements as set forth for a Market Participant in the Market Protocols.

(f) Market Participant shall design, construct, operate and maintain systems and communications equipment in order to: (i) receive SPP deployment instructions for generators pseudo-tying into the SPP Balancing Authority; (ii) account for load pseudo-tying into the SPP Balancing Authority; and (iii) enable SPP to account for congestion and losses associated with generators and loads pseudo-tying out of the SPP Balancing Authority in accordance with the Market Protocols.

(g) Market Participant shall design, construct, operate and maintain real-time and historical systems and communications equipment, at Market Participant’s expense, in order to provide the External Balancing Authority and the SPP Balancing Authority with the corresponding real-time pseudo-tie value. Market Participant’s systems shall provide this signal to the SPP Balancing Authority per the SPP Balancing Authority’s ICCP communication standards. Market Participant’s system shall provide this signal to the External Balancing Authority in a manner mutually agreed to between the External Balancing Authority and the Market Participant.
(h) SPP, in accordance with the Market Protocols, will provide the Market Participant commitment and dispatch instructions for generators pseudo-tying into the SPP Balancing Authority for participation in the Energy and Operating Reserve Markets consistent with such instructions issued to other registered Resources.

(i) For generators pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.

(j) For generators pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(k) For loads pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.

(l) For loads pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(m) The SPP Balancing Authority will coordinate with the External Balancing Authority to include the real time pseudo-tie value in their respective calculations of Net Actual Interchange and Area Control Error as required by the JOA.

(n) If communication is lost between any of the Parties (including communication between SPP and the Market Participant), the External Balancing Authority and the SPP Balancing Authority will freeze at the last known value, as required by the JOA, and it is the responsibility of the Market Participant to verbally communicate changes of the real time pseudo-tie values with SPP and the External Balancing Authority.

(o) Market Participant shall notify SPP and the External Balancing Authority of any real-time circumstances that affect the Market Participant’s obligation or ability to meet the SPP Setpoint Instructions or External Balancing Authority instructions. A generator pseudo-tying into the SPP Balancing Authority will be subject to the same penalties as a Resource under Attachment AE of the SPP Tariff. A generator pseudo-tying out of the SPP Balancing Authority will be subject to the rules and procedures specified by the External Balancing Authority.

(p) The SPP Balancing Authority will coordinate with the External Balancing Authority to integrate the real time pseudo-tie value on an hourly basis and maintain this
information for balancing authority checkout, inadvertent calculations and payback purposes in accordance with the applicable NERC standards, as required by the JOA. For generators and loads pseudo-tying into the SPP Balancing Authority, it is the responsibility of the External Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the External Balancing Authority’s final daily checkout with the SPP Balancing Authority. For generators and loads pseudo-tying out of the SPP Balancing Authority, it is the responsibility of the SPP Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the SPP Balancing Authority’s final daily checkout with the External Balancing Authority.

(q) The Market Participant for generators and loads pseudo-tying into or out of the SPP Balancing Authority Area is responsible for submission of settlement meter data for use in the settlement process of the Real-Time Balancing Market in accordance with the SPP Market Protocols.

(r) Except as otherwise provided in this Section 2, failure by the Market Participant to provide real-time pseudo-tie values in a timely manner constitutes a basis for the immediate suspension of this Agreement by the SPP Balancing Authority. In the event of such suspension, the Market Participant shall provide a remedy for the cause of the failure prior to resumption of participation. In the event of two suspensions within a thirty day period, this Agreement may be terminated, in accordance with Section 7 of this Agreement, at the sole discretion of the SPP Balancing Authority.

3. **Losses.** For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will be responsible for loss compensation to transmission provider(s) to deliver their energy to or receive their energy from the SPP Balancing Authority. Pseudo-tie value(s) will be considered net of losses external to SPP. Losses within the SPP Balancing Authority attributable to the Market Participant’s participation in the Energy and Operating Reserve Markets, including generators and loads pseudo-tying out of the SPP Balancing Authority, shall be handled in the same manner as other Energy and Operating Reserve Markets transactions.

4. **Compensation.** For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will compensate the External Balancing Authority for the reasonable implementation and operations related costs borne by the External Balancing Authority as a result of this Agreement unless the Market Participant and External Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement. For generators and loads pseudo-tying out of the SPP Balancing Authority, Market Participant will compensate the SPP Balancing Authority for the reasonable implementation and operations related costs borne by the SPP Balancing Authority as a result of this Agreement unless the Market Participant and SPP Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement.

5. **Auditing.** Each Party reserves the right to audit records necessary to permit evaluation and verification of claims submitted, and the other Party’s compliance with this Agreement. The
Parties shall retain for a period of three years all information and records relating to the performance of this Agreement. Each Party may examine and copy such information and records at the other Party’s premises during regular business hours and upon advance notice given no less than 15 calendar days prior to such examination.

6. **Effective Date.** The Agreement is effective upon full execution if it is not filed with the Commission. If the Agreement is filed with the Commission, then it is effective upon the later of the date of execution or the date allowed by the Commission. If the parties are unable to resolve any issues, SPP shall file an unexecuted agreement with the Commission, including all agreed-upon non-conforming deviations.

7. **Termination.** Other than as provided in Section 2(r), this Agreement shall terminate on [______](Date), unless extended by agreement of all the Parties. Any Party shall have the right to terminate this Agreement upon ___ month’s notice, subject to receiving all necessary regulatory approvals for such termination.

8. **Governing Law.** The interpretation and performance of this Agreement and each of its provisions shall be governed and construed in accordance with the applicable Federal and/or State laws without regard its conflicts of laws provisions that would apply the laws of another jurisdiction.

9. **Interpretation.** In this Agreement:

   (a) the words “include”, “includes” and “including” are deemed to be followed by the words “without limitation”;

   (b) references to contracts, agreements and other documents and instruments shall be references to the same as amended, supplemented or otherwise modified from time to time;

   (c) references to laws or standards and to terms defined in, and other provisions of, laws or standards shall be references to the same (or a successor to the same) as amended, supplemented or otherwise modified from time to time; and

   (d) references to a person shall include its successors and permitted assigns and, in the case of a governmental or other authority (including SPP and the North American Electric Reliability Corporation), any person succeeding to its functions and capacities.

10. **Severability.** If any provision of this Agreement is held invalid, illegal or unenforceable in any jurisdiction, then, the Parties agree, to the fullest extent permitted by law, that the validity, legality and enforceability of the remaining provisions hereof in such or any other jurisdiction and of such provision in any other jurisdiction shall not in any way be affected or impaired thereby. With respect to the provision held invalid, illegal or unenforceable, the Parties will
amend this Agreement as necessary to effect the original intent of the Parties as closely as possible.

11. **Complete Agreement; Amendments.** This Agreement constitutes the entire agreement among the Parties with respect to the subject matter of this Agreement and supersedes other prior agreements and understandings, both written and oral, among the Parties with respect to the subject matter of this Agreement. This Agreement may be amended, supplemented or otherwise modified only by an instrument in writing signed by all Parties.

12. **Other Obligations.** Nothing in this Agreement is intended to modify or change any obligations or rights under any tariff (including the SPP Tariff), any rate schedule, or any other contract. This Agreement does not in any way provide transmission service or address rates, terms or conditions of transmission service or indicate in any way that transmission service is available or properly awarded. A Party seeking transmission service must still go through the full tariff process to obtain transmission service. This Agreement also does not establish any generation as a designated network resource under the Tariff; the requirements of the Tariff still must be satisfied. Nor does this Agreement make any Party a Market Participant under the SPP Tariff. A Party seeking to become a Market Participant must apply to SPP under the terms of the SPP Tariff and nothing in this Agreement affects its rights or obligations as a Market Participant.

13. **Commission Filing.** If unchanged, a signed version of this form agreement shall not be filed with the Commission. SPP will simply report the existence of a signed agreement in its quarterly reports. If the form agreement is substantively changed, then SPP shall file the revised form agreement with the Commission. The Parties shall be bound to the terms accepted or ordered by the Commission.

14. **Modification.** Nothing in this Agreement is intended to modify or limit the right of SPP to submit under FPA Section 205 or Section 206 unilateral changes to this Agreement (both the form Agreement and any signed agreement); the right of any other Party to seek unilateral changes under FPA Section 206, or the right of the Federal Energy Regulatory Commission to accept any FPA Section 205 filing or to make changes under FPA Section 206 or to initiate proceedings under FPA Section 206.

15. **Charges.** The provisions in this Agreement providing for compensation do not authorize Commission regulated public utilities to impose charges without a separately filed tariff or rate schedule being accepted by the Commission.

16. **Disputes.** Any disputes under this Agreement shall first be resolved pursuant to the dispute resolution procedures in the SPP’s Open Access Transmission Tariff. Any disputes may be brought to the Commission.

17. **Breach.** If any Party breaches the terms of this Agreement, then a non-breaching Party may seek any relief it believes is appropriate at the Commission. A breach is considered a substantive violation of this Agreement. Prior to pursuing a remedy at the Commission for a breach, a non-breaching Party shall provide five business days notice of the breach to the breaching Party. If the breaching Party does not eliminate the breach within five (5) business
days after the notice is received by the breaching Party, then the non-breaching Party may pursue its remedies at the Commission.

18. **Counterparts.** This Agreement may be executed in one or more counterparts, each of which shall be an original but all of which, taken together, shall constitute only one legal instrument. It shall not be necessary in making proof of this Agreement to produce or account for more than one counterpart. The delivery of an executed counterpart of this Agreement by facsimile shall be deemed to be valid delivery thereof.

    The Parties have caused this Agreement to be signed by their authorized representatives on the day and year first above written.

**SPP Balancing Authority**

By:____________________________
    Name:_____________________
    Title:______________________

**Market Participant**

By:________________________
    Name:_____________________
    Title:______________________
EXHIBIT A
ONE-LINE DIAGRAM
EXHIBIT B
BLOCK DIAGRAM
O - Definitions

**OATT:** See “Tariff.”

**Open Access Same-Time Information System (OASIS):** The information system and Internet location where the Transmission Provider posts the information required by 18 C.F.R. § 37 of the Commission’s regulations, and where the Transmission Provider may also post the information required to be posted on its Internet website by 18 C.F.R. § 358 of the Commission’s regulations.

**Operating Reserve Only Resource:** A Resource that cannot be cleared or dispatched for Energy that is qualified to provide any or all of the Operating Reserve products: Regulation-Up, Regulation-Down, Spinning Reserve, Supplemental Reserve, Ramp Capability Up, or Ramp Capability Down, or Uncertainty Reserve. A Resource that cannot be cleared for dispatch or Energy will not be qualified to provide Ramp Capability Up, Ramp Capability Down, or Uncertainty Reserve.

**Oversight Committee:** The organizational group defined in Section 6.4 of the SPP Bylaws.
R - Definitions

**Real-Time:** As defined in Attachment AE to this Tariff.

**Real-Time Balancing Market ("RTBM"):** The market operated by the Transmission Provider continuously in real-time to balance the system through deployment of Energy and to clear–Regulation Up, Regulation Down, Spinning Reserve and Supplemental Reserve each Operating Reserve product.

**Receiving Party:** The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

**Region-wide Annual Transmission Revenue Requirement:** The sum of the annual transmission revenue requirements as set forth in Attachment H, Table 2-A and Table 2-B.

**Region-wide Charge:** Regional component of the charge assessed by the Transmission Provider in accordance with Schedule 11 to recover the Region-wide Annual Transmission Revenue Requirement.

**Region-wide Load Ratio Share:** For application to Section I, Table 2-A of Attachment H, the ratio of a Network Customer’s or Transmission Owner’s Resident Load to total Resident Load in Zones 1 through 18, computed in accordance with Section II.B to Schedule 11 of this Tariff, and calculated on a calendar year basis for the prior calendar year. For application to Section I, Table 2-B of Attachment H, the ratio of a Network Customer's or Transmission Owner’s Resident Load to total Resident Load in the SPP Region, with both numerator and denominator limited to Resident Loads subject to the Region-wide Charge, computed in accordance with Section II.C to Schedule 11 of this Tariff, and calculated on a calendar year basis for the prior calendar year. Customer loads used to determine the Region-wide Load Ratio Share shall be adjusted for real power losses in accordance with the provisions set out in Section 28.5 of this Tariff.
**Region-wide Rate:** Regional component of the rate per kW of Reserved Capacity assessed by the Transmission Provider in accordance with Schedule 11 to recover the Region-wide Annual Transmission Revenue Requirement.

**Regional State Committee:** A voluntary organization comprised of one designated commissioner from each participating state regulatory commission having jurisdiction over an SPP Member, established to collectively provide both direction and input on all matters pertinent to the participation of the Members in SPP pursuant to the SPP Bylaws.

**Regional Transmission Group (RTG):** A voluntary organization of Transmission Owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

**Reliability Unit Commitment:** As defined in Attachment AE of this Tariff.

**Reserve Sharing System:** The Transmission Provider’s computer system that receives and records contingency events and requests for assistance by Reserve Sharing Group members, calculates and communicates the appropriate reserve capacity obligations and reserve energy responsibilities for events to all Reserve Sharing Group members and creates applicable Energy schedules for deployment by the Reserve Sharing Group members.

**Reserved Capacity:** The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.
**Resident Load:** The load specified in Section 41 of the Tariff.

**Resource:** An asset that injects energy into the transmission grid or reduces the withdrawal of energy from the transmission grid including a Demand Response Resource, a Variable Energy Resource, a Dispatchable Resource, External Resource, External Dynamic Resource and a Quick-Start Resource.

**Revenue Requirements and Rates File (RRR File):** A file posted on the SPP website as a reference to: (i) Annual Transmission Revenue Requirements (ATRRs) for Network Integration Transmission Service, as referenced in Attachment H to this Tariff; (ii) Base Plan ATRR allocation; (iii) allocation factors for Base Plan funded projects; (iv) notes on the calculation of Base Plan ATRR amounts on a Region-wide and Zonal basis; (v) ATRR reallocation for Balanced Portfolio projects; (vi) the calculation of Base Plan Point-To-Point Transmission Service rates on a Region-wide and Zonal basis in accordance with Schedule 11; and (vii) the rates for Point-To-Point Transmission Service as referenced in Attachment T in accordance with Schedules 7 and 8.
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1.1 Definitions M

Market Clearing Price (“MCP”)
The price used for settlements of an Operating Reserve product in each Reserve Zone. A separate price is calculated for Regulation-Up Service, Expected Regulation-Up Mileage, Regulation-Down Service, Expected Regulation-Down Mileage, Spinning Reserve and Supplemental Reserve each Operating Reserve product.

Market Flow
The aggregate Megawatt flow on a Coordinated Flowgate or a Reciprocal Coordinated Flowgate caused by the Real-Time Balancing Market.

Market Participant
As defined in Section 1 of the Tariff.

Market Storage Resource (“MSR”)
An ESR that registers consistent with the requirements under Section 2.17 of this Attachment AE.

Marginal Congestion Component (“MCC”)
The calculated portion of the Locational Marginal Price at a Settlement Location representing transmission congestion costs between that Settlement Location and a reference location as calculated under Section 8.3 of this Attachment AE.

Marginal Loss Component (“MLC”)
The calculated portion of the Locational Marginal Price at a Settlement Location representing marginal loss costs between that Settlement Location and a reference location as calculated under Section 8.3 of this Attachment AE.

Maximum Charge Limit
The maximum MW level that an MSR is able to withdraw from the grid during normal operating conditions.
**Maximum Charge Time**
The maximum duration of time that an MSR is able to withdraw from the grid.

**Maximum Discharge Limit**
The maximum MW level that an MSR is able to inject into the grid used during normal operating conditions.

**Maximum Discharge Time**
The maximum duration of time that an MSR is able to inject into the grid.

**Maximum Economic Capacity Operating Limit**
An economic MW level at or below a Resource’s Maximum Normal Capacity Operating Limit used for constraining Energy dispatch and Contingency Reserve clearing during normal system conditions.

**Maximum Emergency Capacity Operating Limit**
The maximum Megawatt level at which a Resource other than a Block Demand Response Resource may operate under Emergency Conditions.

**Maximum Emergency Charge Limit**
The maximum MW level that an MSR is able to withdraw from the grid during an Emergency Condition.

**Maximum Emergency Discharge Limit**
The maximum MW level that an MSR is able to inject into the grid during an Emergency Condition.

**Maximum Normal Capacity Operating Limit**
The maximum Megawatt level at which a Resource may operate continuously.
Maximum Off-line Supplemental Reserve Response Limit
The maximum amount of off-line Supplemental Reserve that can be provided by a Resource.

Maximum Regulation Capacity Operating Limit
The maximum Megawatt level at which a Regulation Qualified Resource, a Regulation-Up Qualified Resource or a Regulation-Down Qualified Resource may operate while providing Regulation Deployment.

Maximum State of Charge
The maximum State of Charge that should not be exceeded.

Megawatt (“MW”)
A measurement unit of the instantaneous demand for Energy.

Meter Agent
An entity responsible for collecting load and Resource data associated with identified Meter Settlement Locations within a Settlement Area for the purpose of energy accounting that impacts market settlements.

Meter Data Submittal Location
One or more Meter Settlement Locations contained within a single Settlement Area for which meter data is submitted to the Transmission Provider by the Meter Agent for settlement purposes.

Meter Settlement Location
The point at which a Market Participant’s registered load and Resources interchange Energy with the Real-Time Balancing Market.

Minimum Charge Limit
The minimum MWs level an MSR is able to withdraw from the grid during normal operating conditions.

**Minimum Charge Time**
The minimum duration of time an MSR is able to withdraw from the grid.

**Minimum Discharge Limit**
The minimum MW level that an MSR is able to inject into the grid during normal operating conditions.

**Minimum Discharge Time**
The minimum duration of time that an MSR is able to inject into the grid.

**Minimum Economic Capacity Operating Limit**
A Megawatt level at or above a Resource’s Minimum Normal Capacity Operating Limit used for energy dispatch at a minimum level during normal operating conditions.

**Minimum Emergency Capacity Operating Limit**
The minimum Megawatt level at which a Resource other than a Block Demand Response Resource may operate under Emergency Conditions.

**Minimum Emergency Charge Limit**
The minimum MW level that an MSR is able to withdraw from the grid during an Emergency Condition.

**Minimum Emergency Discharge Limit**
The minimum MW level that an MSR is able to inject into the grid during an Emergency Condition.

**Minimum Normal Capacity Operating Limit**
The minimum Megawatt level at which a Resource may operate continuously.
**Minimum Regulation Capacity Operating Limit**
The minimum Megawatt level at which a Regulation Qualified Resource, a Regulation-Up Qualified Resource or a Regulation-Down Qualified Resource may operate while providing Regulation Deployment.

**Minimum Run Time**
The minimum length of time a Resource must run from the time the Resource is put online to the time the Resource is shut-down.

**Minimum State of Charge**
The minimum State of Charge that should be maintained.

**Min-To-Off Time**
The time for a Resource to de-synchronize from the grid starting from the Resource’s Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Minimum Charge Limit, as applicable.

**Most Severe Single Contingency**
The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority’s area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of an RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

**Multi-Configuration Resource (“MCR”)**
A combined cycle Resource registered consistent with the offer submission option as defined under Section 4.1.2.2(4) of this Attachment AE.
Multi-Day Reliability Assessment

The process to assess Resource adequacy for the Operating Day, commit Resources with long Start-Up Times that cannot be considered as part of the Day-Ahead Market or Day-Ahead Reliability Unit Commitment, and communicate commitment of such Resources as necessary.
1.1 Definitions

Offer
A commitment to sell (i) a quantity of Energy at a specific minimum price that includes a Resource Offer, a Virtual Energy Offer or an Import Interchange Transaction Offer, or (ii) a quantity of Transmission Congestion Rights at a specific minimum price, where such quantities may be submitted in 0.1 MW increments.

Off-Peak
As defined in Schedule 1 of the Tariff.

On-Peak
As defined in Schedule 1 of the Tariff.

Operating Day
A daily period beginning at midnight.

Operating Hour
A sixty (60) minute period of time during the Operating Day corresponding to a clock hour typically expressed as hour-ending.

Operating Reserve
Resource capacity required to provide for Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, and Ramp Capability Down, and Uncertainty Reserve for reasons including, but not limited to; load forecasting error, instantaneous load changes, Variable Energy Resource forecast error, and equipment forced outages.

Operating Tolerance
The Megawatt range of actual Resource output above and below the Resource’s average Setpoint Instruction over the Dispatch Interval where the Resource will not be subject to charges associated with Uninstructed Resource Deviation.
Out-of-Merit Energy (OOME)

(a) A Dispatch Instruction from the Transmission Provider to address an Emergency Condition or reliability issue that the market systems cannot resolve, (b) a Dispatch Instruction from a local transmission operator to address a Local Emergency Condition, or (c) a non-Energy manual exclusion, by the Transmission Provider, of a Resource from providing Operating Reserves after the Day-Ahead Market clears.
1.1 Definitions R

**Ramp Capability Down**
An Operating Reserve product, procured by the Transmission Provider from a Resource capable of following Setpoint Instructions, that is reserved to provide downward flexibility during periods in which net obligations decrease in future Dispatch Intervals. There is no explicit offer for this product. The value is derived using loss of opportunity.

**Ramp Capability Up**
An Operating Reserve product, procured by the Transmission Provider from a Resource capable of following Setpoint Instructions, that is reserved to provide upward flexibility during periods in which net obligations increase in future Dispatch Intervals. There is no explicit offer for this product. The value is derived using loss of opportunity.

**Ramp-Rate-Down**
A curve specifying MW/minute ramp rates applicable between Resource operating ranges that is used to dispatch Resources in the down direction. For MSRs, Ramp-Rate-Down is the rate at which a MSR can move from zero output to Maximum Charge Limit, which is represented as a negative (-) value for the MW breakpoint. This rate also represents the rate at which the MSR can move from Maximum Discharge Limit to zero output.

**Ramp-Rate-Up**
A curve specifying MW/minute ramp rates applicable between Resource operating ranges that is used to dispatch Resources in the up direction. For MSRs, Ramp-Rate-Up is the rate at which a MSR can move from zero output to Maximum Discharge Limit. This rate also represents the rate at which the MSR can move from Maximum Charge Limit, which is represented as a negative (-) value for the MW breakpoint, to zero output.

**Real-Time**
The continuous time period during which the Real-Time Balancing Market is operated.
**Real-Time Balancing Market (“RTBM”)**
As defined in Section 1 of the Tariff.

**Real-Time Capability**
The amount (MW) of real power output the Resource is capable of instantaneously producing, excluding any dispatch, deployment, or curtailment instructions.

**Real-Time Load Ratio Share**
The sum of a Market Participant’s Reported Load, Self-Charging MSRs, and Export Interchange Transactions at all Settlement Locations divided by the sum of all Market Participants’ Reported Load, Self-Charging MSRs, and Export Interchange Transactions at all Settlement Locations for a given hour.

**Reciprocal Coordinated Flowgate**
A Coordinated Flowgate defined within a joint operating agreement between SPP and another transmission provider as being affected by the transmission of Energy on both of their respective transmission systems.

**Reference Bus**
The location on the Transmission System relative to which all mathematical quantities, including shift factors and penalty factors relating to physical operation, will be calculated.

**Regulation Deployment**
The utilization of Regulation-Up Service and/or Regulation-Down Service through automatic generation control equipment to automatically and continuously adjust Resource output to balance the real power requirements of the SPP Balancing Authority Area.

**Regulation-Down**
An Operating Reserve product procured by the Transmission Provider from qualified Resources that reduce their energy output (or increase consumption of the Demand Response Load
associated with a qualified Dispatchable Demand Response Resource) in response to a Regulation Deployment instruction from the Transmission Provider.

**Regulation-Down Mileage Factor**
A factor determined through historical Regulation Deployment analysis that represents the ratio of the Transmission Provider’s total Instructed Regulation-Down Mileage to the Transmission Provider’s total cleared Regulation-Down Service. The Regulation-Down Mileage Factor shall initially be set equal to 1.0 and shall be updated periodically pursuant to the Market Protocols.

**Regulation-Down Mileage Offer**
The price at which a Regulation Qualified Resource or a Regulation-Down Qualified Resource has agreed to sell Expected Regulation-Down Mileage.

**Regulation-Down Offer**
The price at which a Regulation Qualified Resource or a Regulation-Down Qualified Resource has committed to sell Regulation-Down.

**Regulation-Down Qualified Resource**
A Resource that has met the requirements to be eligible to submit Regulation-Down Offers and Regulation-Down Mileage Offers into the Energy and Operating Reserve Markets.

**Regulation-Down Scarcity Factor**
A multiplier used to define shortage regions of Regulation-Down and the appropriate scarcity price value associated with the shortage.

**Regulation-Down Service**
The provision of Actual Regulation-Down Mileage associated with cleared Regulation-Down Service MW in response to Regulation Deployment instructions.

**Regulation-Down Service Offer**
The sum of (i) a Resource’s Regulation-Down Mileage Offer multiplied by the Regulation-Down Mileage Factor and (ii) that Resource’s Regulation-Down Offer.

**Regulation Mileage Operating Tolerance**
The allowable percentage deviation below a Resource’s Instructed Regulation-Up Mileage and/or Instructed Regulation-Down Mileage over the Dispatch Interval where the Resource will settle based upon Instructed Regulation-Up Mileage and/or Instructed Regulation-Down Mileage versus Actual Regulation-Up and/or Actual Regulation-Down Mileage. Such percentage is set at 5%.

**Regulation Qualified Resource**
A Resource that has met the requirements to be eligible to submit Regulation-Up Offers, Regulation-Up Mileage Offers, Regulation-Down Offers and Regulation-Down Mileage Offers into the Energy and Operating Reserve Markets.

**Regulation Response Time**
The maximum amount of time allowed for a Resource to move its output from zero (0) Regulation Deployment to the full amount of Regulation-Up cleared or to move from zero (0) Regulation Deployment to the full amount of Regulation-Down cleared.

**Regulation-Up**
An Operating Reserve product procured by the Transmission Provider from qualified Resources that increase their energy output (or reduce consumption of the Demand Response Load associated with a qualified Dispatchable Demand Response Resource) in response to a Regulation Deployment instruction from the Transmission Provider.

**Regulation-Up Mileage Factor**
A factor determined through historical Regulation Deployment analysis that represents the ratio of the Transmission Provider’s total Instructed Regulation-Up Mileage to the Transmission Provider’s total cleared Regulation-Up Service. The Regulation-Up Mileage Factor shall initially be set equal to 1.0 and shall be updated periodically pursuant to the Market Protocols.
**Regulation-Up Mileage Offer**
The price at which a Regulation Qualified Resource or a Regulation-Up Qualified Resource has agreed to sell Expected Regulation-Up Mileage.

**Regulation-Up Offer**
The price at which a Regulation Qualified Resource or a Regulation-Up Qualified Resource has committed to sell Regulation-Up.

**Regulation-Up Qualified Resource**
A Resource that has met the requirements to be eligible to submit Regulation-Up Offers and Regulation-Up Mileage Offers into the Energy and Operating Reserve Markets.

**Regulation-Up Scarcity Factor**
A multiplier used to define shortage regions of Regulation-Up and the appropriate scarcity price value associated with the shortage.

**Regulation-Up Service**
The provision of Actual Regulation-Up Mileage associated with cleared Regulation-Up Service MW in response to Regulation Deployment instructions.

**Regulation-Up Service Offer**
The sum of (i) a Resource’s Regulation-Up Mileage Offer multiplied by the Regulation-Up Mileage Factor and (ii) that Resource’s Regulation-Up Offer.

**Reliability Unit Commitment (“RUC”)**
The process performed by the Transmission Provider to assess resource and Operating Reserve adequacy for the Operating Day, commit or de-commit resource as necessary, and communicate commitment or de-commitment of Resources to the appropriate Market Participants as necessary.
**Reliability Unit Commitment Period ("RUC Commitment Period")**
The contiguous period of time between a Resource’s Reliability Unit Commitment Commit Time and Reliability Unit Commitment De-Commit Time.

**Reported Load**
A Market Participant's actual value of energy withdrawn from the Transmission System at a Settlement Location adjusted as described under Section 8.6.1.1 of Attachment AE and further adjusted, if necessary, to account for distribution system losses between the actual metering point and the Transmission System Settlement Location as described under Appendix D of the Market Protocols.

**Reservation Capacity**
The reservation Megawatt between a specified source and sink associated with SPP Transmission Service.

**Reserve Sharing Event**
A request for assistance to deploy Contingency Reserve by any member of the Reserve Sharing Group following the sudden loss of a Resource.

**Reserve Sharing Group**
A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority’s use in recovering from contingencies within the group.

**Reserve Zone**
A zone containing a specific group of Price Nodes for which a minimum and maximum Operating Reserve requirement is calculated.

**Resettlement**
The settlement of an Operating Day subsequent to the posting of the S120 Scheduled Settlement Statement for that Operating Day.
**Residual Load**
Settlement Area Net Load less all other directly metered Reported Load within the Settlement Area.

**Resource**
As defined in Part I, Section 1 of this Tariff.

**Resource Hub**
A Settlement Location consisting of an aggregation of Resource Price Nodes developed for financial and trading purposes.

**Resource Offer**
For a Resource, the combination of its Start-Up Offer, No-Load Offer, Energy Offer Curve, Transition State Offer, Regulation-Up Service Offer, Regulation-Down Service Offer, Spinning Reserve Offer, Supplemental Reserve Offer, Uncertainty Reserve Offer, and Resource physical operating parameters.
1.1 Definitions U

**Uncertainty Reserve**
An Operating Reserve product procured by the Transmission Provider from the portion of a dispatchable and participating Resource’s capability that is reserved for potentially increasing net obligations for future Dispatch Intervals. The value for Resources clearing online Uncertainty Reserve is derived using loss of opportunity, similar to Ramp Capability Up. Resources capable of clearing offline Uncertainty Reserve may submit an Uncertainty Reserve Offer, and must not be scheduled to come online within the Uncertainty Reserve response time more quickly than the operator calling on the Resource in the Dispatch Interval.

**Uncertainty Reserve Offer**
The price at which a Resource has agreed to sell offline Uncertainty Reserve. Uncertainty Reserve Offers do not apply to online Uncertainty Reserves.

**Uninstructed Resource Deviation (“URD”)**
The Megawatt amount by which a Resource’s actual output in a Dispatch Interval is above or below that Resource’s average Setpoint Instruction in the Dispatch Interval.

**Unused Regulation-Down Mileage**
The amount calculated under Section 8.6.2 of this Attachment AE.

**Unused Regulation-Up Mileage**
The amount calculated under Section 8.6.2 of this Attachment AE.
2.10.5 Uncertainty Reserve Qualified Resources

Uncertainty Reserve is procured from Resources to respond to potential future net obligation changes in the Energy and Operating Reserve Markets. There are no specific testing requirements for a Resource to become an Uncertainty Reserve qualified Resource. A Resource that is (1) capable of following RTBM Dispatch Instruction and (2) that has the ability to increase and maintain its output for at least the duration of the Uncertainty Reserve response time (once the specified resource output is achieved), will be considered qualified to clear Uncertainty Reserve. Resources that are physically capable will make themselves available (through self-certification), but may be able to opt-out with qualification and dispatch status. The product may be provided by online resources and offline resources. Uncertainty Reserve qualified resources will offer 0 MW offline Uncertainty Reserve, when they are not capable of providing offline Uncertainty Reserve, but may provide online Uncertainty Reserve.
2.11.1 Day-Ahead Market

A. Each Market Participant must satisfy the must offer obligation for an Asset Owner as set forth in Section 2.11.1(B) of this Attachment AE based on the following criteria:

(1) A Market Participant’s load for an Asset Owner for purposes of this section shall be equal to that Market Participant’s maximum hourly Reported Load for an Asset Owner for the Operating Day. Such Asset Owner’s Reported Load shall include load registered as described under Section 2.2(11) of this Attachment AE, where the buyer’s Reported Load shall be reduced by the amount of the buyer’s load registered by the seller and the seller’s Reported Load shall be increased by the amount of the buyer’s load registered by the seller. If an MSR is Self-Charging during the maximum Reported Load hour, the Market Participant’s available generation that is used to satisfy the must offer obligation is reduced by the Self-Charging MW.

(2) A Market Participant’s daily Operating Reserve obligation for an Asset Owner shall be equal to the sum of that Market Participant’s maximum daily Regulation-Up Service, Regulation-Down Service, Contingency Reserve, Ramp Capability Up, and Ramp Capability Down, and Uncertainty Reserve obligations for an Asset Owner as estimated by the Transmission Provider in accordance with Section 3.1.4(3) of this Attachment AE.

(3) A Market Participant may satisfy this requirement by offering Resources for an Asset Owner with a commitment status indicating either that the Market Participant is self-committing the Resource, the Resource may be committed by the Transmission Provider, or the Resource may be committed by the Transmission Provider only to alleviate an anticipated Emergency Condition or Local Reliability Issue, as specified in Sections 4.1(10)(a), 4.1(10)(b), and 4.1(10)(c) of the Attachment AE.

(4) A Market Participant’s net resource capacity for an Asset Owner, for purposes of this section shall include:

i. Offered capacity by Resources identified in Section 2.11.1(A)(3) of Attachment AE less the Operating Reserve obligation identified in Section 2.11.1(A)(2) of Attachment AE; and
Firm power purchases less firm power sales, except that, if the seller has registered the buyer’s load associated with a firm power sale as described in Section 2.2(11) of this Attachment AE, such firm power sale shall not act to increase the buyer’s net resource capacity or act to reduce the seller’s net resource capacity. For purposes of this Section 2.11.1 of this Attachment AE firm power purchases and firm power sales shall mean sales and purchases that are deliverable with transmission service comparable to Firm Point-To-Point Transmission Service or Firm Network Integration Transmission Service with the supplier assuming the obligation to provide both capacity and energy. Additionally, firm power purchases shall include an Asset Owner’s share of a Jointly Owned Unit to the extent that such shares have not been registered as separate Resources either under Jointly Owned Unit individual Resource option as described under Section 2.2(4) of this Attachment AE, or under Combined Interest Resource modeling as described under Section 2.2(18) of this Attachment AE.

In order to verify firm power purchases and firm power sales, supporting documentation must be provided to the Market Monitor upon request. Market Participants have the option to input information regarding firm power purchases and firm power sales into the Market Monitor website. If no information is input into this website, the Market Monitor will contact the Market Participant for that information. The Market Monitor may communicate with the counterparty to confirm the firm purchase or sale and will include the transacted MWs to calculate net resource capacity for both purchaser and seller. If one of the parties disputes the firm purchase or sale to the Market Monitor, then the firm purchase or sale will not be used in the calculation of either the purchaser’s or seller’s net resource capacity subject to any dispute resolution.

B. A Market Participant’s compliance with the must offer obligation for an Asset Owner is as follows:
(1) A Market Participant that has offered all of its available Resources for an Asset Owner, with a commitment status described in Sections 4.1(10)(a), 4.1(10)(b), and/or 4.1(10)(c) of this Attachment AE, for an hour of the Operating Day is deemed to be in compliance with the must offer requirement for that Asset Owner for that hour regardless of its maximum hourly Reported Load and/or, Operating Reserve obligation.

(2) A Market Participant that does not meet the condition described in Section 2.11.1(B)(1) of this Attachment AE for an Asset Owner for an hour of the Operating Day, but has net resource capacity for that Asset Owner for that hour greater than or equal to 90% of its load for that Asset Owner as described in Section 2.11.1(A)(1) of this Attachment AE is deemed to be in compliance for that Asset Owner with the must offer requirement for that hour.

(3) To the extent that a Market Participant does not meet the conditions described in either Section 2.11.1(B)(1) or (2) of this Attachment AE for an Asset Owner, the Market Participant shall be deemed noncompliant with the must offer requirement for that Asset Owner for that hour and will be assessed a penalty for that hour as determined in Section 3.9 of Attachment AF of this Tariff.

C. Market Monitor shall monitor a Market Participant’s Load, Operating Reserve obligation, offered Resources and net resource capacity, for an Asset Owner for each hour of the Operating Day to determine whether the Market Participant has complied with the must offer obligation set forth in Section 2.11.1(B) of this Attachment AE.
2.17 Electric Storage Resource

ESRs may register as any valid Resource type and are subject to the same service provision rules as any other Resource within that type.

(1) If not registered as an MSR the energy withdrawal from the Transmission System must be included in a Load Settlement Location and are subject to the same rules as other Load.

(2) If an ESR is registered as an MSR, the following applies:
   a) MSRs may provide Energy, Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve, and Uncertainty Reserve services upon meeting the technical and applicable requirements for these services in this Attachment AE and the Market Protocols.
   b) MSRs must provide Offer parameters as prescribed in Section 4.1 of this Attachment AE.
   c) MSR Offer Curves may include negative MW values to account for the entire dispatchable range of the MSR.
   d) As with other Resources, the metering requirements for MSRs include real-time and settlement quality metering. For MSRs that are not directly connected to the Transmission System, metering may include facilities used by the distribution company.
   e) Self-Charging MSRs or MSRs charging beyond the instructed amount are subject to all applicable transmission charges under the Tariff.
   f) Market Participants registering an MSR must also request transmission service under Part II or Part III of this Tariff.
      i. In the absence of explicit transmission service reservation arrangements by the Market Participant for the uninstructed energy withdrawals, the Market Participant will be billed the unreserved use rate as defined in Section 13.7 (c) or 14.5 of this Tariff.
      ii. Dispatch Instruction by the Transmission Provider for the MSR to provide Energy, Regulation-Up, Regulation-Down, Spinning Reserve, or
Supplemental Reserve that incidentally results in charging activity shall not be subject to a bill for transmission service during those actions.

g) The Real-Time Energy consumption is settled at the LMP as per Section 8.3 of this Attachment AE.

i. In the event that the MSR is not directly connected to the Transmission System and the distribution company is unable or unwilling to separate the charging activity from other retail service, the MSR will not be subject to settlement by the Transmission Provider for either the transmission charge or the energy consumption.

h) MSRs are not considered continuously dispatchable in a given interval if a directional commitment limitation exists for that interval. A directional commitment limitation occurs when the Minimum Charge Time is not equal to zero, Minimum Discharge Time is not equal to zero, Minimum Charge Limit is not equal to zero, or Minimum Discharge Limit is not equal to zero. If such a limitation exists, the MSR may offer either charge or discharge capacity in a given interval but not both. MSRs that do not have a directional commitment limitation are considered continuously dispatchable and will be evaluated for commitment and dispatch from the Maximum Charge Limit to the Maximum Discharge Limit.
The Transmission Provider shall calculate the amount of Operating Reserves required for the Operating Day, on both a system-wide and Reserve Zone basis, in order to comply with the reliability requirements specified in the SPP Criteria. In addition, the Transmission Provider shall calculate the amount of Instantaneous Load Capacity required for the Operating Day on a system-wide basis in order to ensure that load can be reliably serviced in real-time. The Transmission Provider shall, on a daily basis:

1. Calculate the hourly Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, and Ramp Capability Down, and Uncertainty Reserve requirements on an SPP Balancing Authority Area basis and post such results by 0600 hours Day-Ahead for use in the Day-Ahead Market, Day-Ahead RUC, Intra-Day RUC and RTBM;

2. Calculate the total minimum and total maximum Operating Reserve requirement for Operating Reserve deployment in the up direction and for deployment of Operating Reserve in the down direction for each Reserve Zone. These minimum and maximum Operating Reserve requirements will be determined by conducting a simulated energy transfer study for each hour of the Operating Day on the transmission system, reflecting expected outages and economic energy flows, in order to determine the energy transfer limitations into or out of a Reserve Zone in any hour. If a Reserve Zone is unable to import enough Energy after a contingency and still maintain all necessary operating limits, a minimum amount of Operating Reserve may be required to be carried in that Zone. The minimum Operating Reserve requirement is the largest difference between the Resource MW lost in the simulated contingency and the resulting import capability of that Reserve Zone. Similarly, if a Reserve Zone is unable to export additional Energy after a contingency outside of that Reserve Zone, then a maximum amount of Operating Reserve that is deliverable from that Zone will be specified in order to ensure that deliverable reserves are carried in other Zones. The maximum Operating Reserve limitation is equal to the export capability of that Reserve Zone when replacing Energy lost due to a Resource contingency outside of that
Reserve Zone. The Transmission Provider may, at its option, set specific Regulation-Up and/or Spinning Reserve minimum requirements for each Reserve Zone, as needed, to address reliability issues that can only be alleviated through carrying synchronized reserves. In such cases, the Transmission Provider will include these minimum Regulation-Up and/or Spinning Reserve requirements when posting the Operating Reserve requirements by 0600 Day-Ahead;

(3) Estimate each Market Participant’s Operating Reserve obligation by Asset Owner in each Reserve Zone and provide such information to Market Participants by 0600 hours Day-Ahead. The Transmission Provider shall calculate such estimates by multiplying the system-wide Operating Reserve requirements calculated in (1) above by the Transmission Provider’s estimate of each Asset Owner’s load in each Reserve Zone divided by the Transmission Provider’s estimate of system-wide load;

(4) The Transmission Provider may increase Operating Reserve requirements for the Day-Ahead RUC, Intra-Day RUC and RTBM above the requirements used in the Day-Ahead Market, including changes to Reserve Zone minimums and maximums, as required to meet increases in reliability requirements caused by changes in system conditions; and

(5) Calculate the hourly Instantaneous Load Capacity requirements for an interval on an SPP Balancing Authority Area basis for use in the Day-Ahead Market, Day-Ahead RUC and Intra-Day RUC in accordance with the calculation procedures specified in the Market Protocols.
3.1.7 Product Substitution

To ensure rational pricing of cleared Operating Reserve products, the SCED algorithm will include product substitution logic as follows:

A. Any Regulation-Up Offers may be used to meet Contingency Reserve requirements if Regulation-Up Offer is more economic or is required to meet the overall Contingency Reserve requirement;

B. Any Spinning Reserve Offers may be used to meet Supplemental Reserve requirements if the Spinning Reserve Offer is more economic or is required to meet the overall Operating Reserve requirement;

C. The product substitution logic ensures that the MCP for Regulation-Up Service is always greater than or equal to the Spinning Reserve MCP and that the Spinning Reserve MCP is always greater than or equal to the Supplemental Reserve MCP.

D. Ramp Capability Up and Ramp Capability Down products are not eligible for product substitution with other Operating Reserves.

E. Uncertainty Reserve is not eligible for product substitution with other Operating Reserves.
3.5 **Integrated Marketplace Pricing**

The Transmission Provider shall calculate Day-Ahead Market and RTBM LMPs for Energy at each Settlement Location.


The Transmission Provider shall calculate annual and monthly Auction Clearing Prices (“ACPs”) at each Settlement Location.
4.1 Offer Submittal

Beginning seven (7) days prior to the Operating Day, Market Participants may begin to submit Offers for use in the Day-Ahead Market and Offers for use in the RTBM. Day-Ahead Market Offers may be updated up to the close of the Day-Ahead Market and RTBM Offers may be updated thirty (30) minutes prior to each Operating Hour. Offer submittals shall conform to the following:

(1) Offers submitted in the Day-Ahead Market are independent from Offers submitted in the RTBM except that, if Regulation-Up Service and/or Regulation-Down Service is cleared in the Day-Ahead Market, Regulation-Up Mileage Offers and/or Regulation-Down Mileage Offers for the associated Resources for use in the RTBM are set equal to the Regulation-Up Mileage Offers and/or Regulation-Down Mileage Offers for the associated Resources submitted for use in the Day-Ahead Market;

(2) Market Participants may specify that the Offers submitted in the Day-Ahead Market also apply in the RTBM;
   (a) Such an Offer shall be rejected in the RTBM if the Market Participant has submitted a Resource commitment status of “not participating” as described in Section 4.1(10)(e) of this Attachment AE and the Resource is not participating in the Day-Ahead Market.

(3) Submitted Resource Offers will automatically roll forward hour to hour within each respective market only when no Resource Offer has been submitted for that interval;

(4) Offers may be submitted that vary for each hour of the Operating Day, except the Offer parameters related to unit commitment as defined in the Market Protocols for which a single value is submitted. These unit commitment Offer parameters will automatically roll forward in each hour of the subsequent Operating Day only when no unit commitment Offer parameters have been submitted for that Operating Day;

(5) Offers submitted for use in the RTBM are also used in the RUC;
(6) Resource Offers may only be submitted at Resource Settlement Locations, Import Interchange Transaction Offers may only be submitted at External Interface Settlement Locations and Virtual Energy Offers may be submitted at any Settlement Location;

(7) For Regulation Qualified Resources and Regulation-Up Qualified Resources, Market Participants may submit Regulation-Up Offers, Regulation-Up Mileage Offers, Spinning Reserve Offers and Supplemental Reserve Offers provided that if the Regulation-Up Offer is negative, the Regulation-Up Mileage Offer must equal zero. For Regulation-Down Qualified Resources and Regulation Qualified Resources, Market Participants may submit Regulation-Down Offers and Regulation-Down Mileage Offers provided that if the Regulation-Down Offer is negative, the Regulation-Down Mileage Offer must equal zero. For Spin Qualified Resources, Market Participants may submit Resource Offers for Spinning Reserve and Supplemental Reserve. For Supplemental Qualified Resources, Market Participants may submit Resource Offers for Supplemental Reserve. If a Spinning Reserve Offer is submitted for a Resource, and a Resource Offer for Supplemental Reserve is not submitted, then the Supplemental Reserve Offer is set equal to zero. Resource qualifications are verified by the Transmission Provider as part of the registration process as follows:

(a) A Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource must pass a specific regulation test as defined in Section 2.10.3 of this Attachment AE and must be capable of deploying one hundred percent (100%) of cleared Regulation-Up and/or Regulation-Down within the Regulation Response Time for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(b) A Spin Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Spinning Reserve and/or cleared Supplemental Reserve within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and
provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(c) Supplemental Qualified Resource:

(i) A Supplemental Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Supplemental Reserve from an off-line state within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(ii) Alternatively, an MCR may also become a Supplemental Qualified Resource by self-certifying that the MCR is capable of deploying 100% of cleared Supplemental Reserve through a transition to a higher capacity configuration within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(d) An Uncertainty Reserve Qualified Resource must self-certify that the Resource is capable of following RTBM Dispatch Instruction and has the ability to increase and maintain its output for at least the duration of the Uncertainty Reserve response time (once the specified resource output is achieved).

(8) Resource Offers are limited by the Offer caps and floors specified in Section 4.1.1 of this Attachment AE;

(9) The Resource Offer parameters that constitute a valid Offer for use in either the Day-Ahead Market or RTBM are submitted using the data formats, procedures, and information defined in the Market Protocols and will include the following (as further defined in the Market Protocols):

- Resource Name
- Resource Type
- Start-up Offer
- No-Load Offer
- Energy Offer Curve
- Transition State Offer (for an MCR)
- Transition State Time (for an MCR)
- Regulation–Up and Regulation-Down Offers
- Regulation-Up Mileage and Regulation-Down Mileage Offers
- Spinning and Supplemental Reserve Offers
  - Uncertainty Reserve Offers
- Sync-To-Min and Min-To-Off Times
- Start-Up Time
- Hot to Intermediate and Hot to Cold Times (not applicable to an MSR)
- Maximum Daily and Weekly Starts
- Maximum Daily Energy
- Maximum and Minimum Run Times
- Plant Minimum Down Time (for an MCR)
- Plant Minimum Run Time (for an MCR)
- Group Minimum Down Time (for an MCR)
- Group Minimum Run Time (for an MCR)
- Minimum Down Time
- Minimum Emergency Capacity Operating Limit and Run Time (not applicable to an MSR)
- Minimum Normal, Economic, and Regulation Capacity Operating Limits (not applicable to an MSR)
- Maximum Normal, Economic, and Regulation Capacity Operating Limits (not applicable to an MSR)
- Maximum Emergency Capacity Operating Limits and Run Time (not applicable to an MSR)
- Maximum Off-line Supplemental Reserve Response Limit
- Maximum Transition State Supplemental Reserve Resource Response Limit (for an MCR)
- Ramp-Rate-Up and Ramp-Rate-Down
- Turn-Around Ramp Rate Factor
- Regulation Ramp Rate
- Contingency Reserve Ramp Rate
- Resource Status
- Interest Percent Share
- State of Charge Forecast (MSR only)
- Maximum and Minimum State of Charge (MSR only)
- Maximum and Minimum Charge Limit (MSR only)
- Maximum and Minimum Discharge Limit (MSR only)
- Maximum and Minimum Charge Time (MSR only)
- Maximum and Minimum Discharge Time (MSR only)
- ESR Loss Factor (MSR only)
- Maximum and Minimum Emergency Charge Limit (MSR only)
- Maximum and Minimum Emergency Discharge Limit (MSR only)

(10) Market Participants must specify a Resource commitment status as part of the Resource Offer using the data formats, procedures, and information defined in the Market Protocols. Market Participants use the commitment status to indicate:
(a) Whether they are self-committing a Resource;
(b) Whether the Resource may be committed by the Transmission Provider;
(c) Whether the Resource may be committed by the Transmission Provider only to alleviate an anticipated Emergency Condition or local reliability issue;
(d) Whether the Resource is on an outage; or
(e) Whether the Resource is not participating in the Day-Ahead Market.

(11) Market Participants must specify a Resource dispatch status as part of the Resource Offer using the data formats, procedures and information defined in the Market Protocols. Market Participants use the dispatch status to notify the Transmission Provider whether the Resource is:
(a) Eligible for Energy Dispatch;
(b) Eligible for Operating Reserve clearing; or
(c) Self-scheduled for Operating Reserve.
If the dispatch status for a Resource does not indicate it is eligible for Energy Dispatch, then such Resource shall not be subject to charges and credits calculated under Section 8.6.15 of this Attachment AE and shall not be subject to the deviation calculations under Sections 8.6.7(A)(2)(e) and 8.6.7(A)(2)(g) of this Attachment AE.

(12) Resource limits submitted as part of the Resource Offer must pass the validation rules defined in the Market Protocols, otherwise, the Resource Offer will be rejected; and

(13) The Market Participant must comply with the must-offer requirements as defined in Section 2.11 of this Attachment AE.
4.1.1 Offer Caps and Floors

Submission of Energy Offer Curves, Start-Up Offers, No-Load Offers, and Operating Reserve Offers by Market Participants for use in the Day-Ahead Market and the RTBM shall be limited by the following Offer caps and floors:

1. Safety-net Energy Offer cap = $1,000/MWh; Energy Offers greater than $1,000/MWh are subject to Section 3.2(F) of Attachment AF of this Tariff.
2. Virtual Energy Offer Cap = $2,000/MWh;
3. Import/Export Transaction Offer Cap = $2,000/MWh;
4. Regulation-Up Service Offer cap = $500/MW;
5. Regulation-Down Service Offer cap = $500/MW;
6. Contingency Reserve Offer cap = $100/MW;
7. Energy Offer floor = Negative $500/MWh;
8. Regulation Service Offer floor = Negative $500/MW;
9. Regulation-Up Mileage Offer floor = $0/MW;
10. Regulation-Down Mileage Offer floor = $0/MW;
11. Contingency Reserve Offer floor = Negative $100/MW;
12. Start-Up Offer floor = $0;
13. No-Load Offer floor = $0;
14. Uncertainty Reserve Offer cap = $1000/MW;
15. Uncertainty Reserve Offer floor = $0/MW.

In addition to these Offer caps and floors, submission of Offers may be limited by the requirements of Attachment AF of this Tariff.
5.1.3 Day-Ahead Market Results

The Transmission Provider will notify each Market Participant of the Day-Ahead Market results for each hour of the Operating Day.

A. The following results are communicated to each Market Participant for only its specific Resources, no later than the posting of the Day-Ahead Market:

(1) Cleared Resource quantities for Energy, Regulation-Up Service, Regulation-Down Service, Spinning Reserve, Supplemental Reserve, Ramp Capability Up, or Ramp Capability Down; or Uncertainty Reserves:

(a) Cleared Offers for Energy associated with Resource Offers represent a physical Resource commitment.

(b) Resources committed by the Transmission Provider in the Day-Ahead Market that incur one or more start-up costs within the Operating Day as a result of the Transmission Provider Day-Ahead Market commitment are guaranteed to receive revenues that are at least equal to the Resource Offer costs for the cleared amount of Energy, Regulation-Up Service, Regulation-Down Service, Spinning Reserve or Supplemental Reserve for that Resource.

(c) Cleared Regulation-Up Service MWs represent only those MWs cleared to meet the Regulation-Up Service requirement.

(d) Cleared Regulation-Down Service MWs represent only those MWs cleared to meet the Regulation-Down Service requirement.

(e) Cleared Spinning Reserve MWs represent the Spinning Reserve MWs cleared to meet the Spinning Reserve requirement and Regulation-Up Service MWs cleared to meet the Spinning Reserve requirement through product substitution as described under Section 3.1.7 of this Attachment AE.

(f) Cleared Supplemental Reserve MWs represent the sum of Supplemental Reserve MWs cleared to meet the Supplemental Reserve requirement and Regulation-Up Service MWs and Spinning Reserve MWs cleared to meet the Supplemental Reserve requirement through product substitution as described under Section 3.1.7 of this Attachment AE.
(g) Cleared Ramp Capability Up MWs represent only those MWs cleared to meet the Ramp Capability Up requirement.

(h) Cleared Ramp Capability Down MWs represent only those MWs cleared to meet the Ramp Capability Down requirement.

(i) Cleared Uncertainty Reserve MWs represent only those MWs cleared to meet the Uncertainty Reserve requirement.

(2) Cleared Virtual Energy Offers;
(3) Cleared Import Interchange Transaction Offers;
(4) Cleared Demand Bids;
(5) Cleared Virtual Energy Bids;
(6) Cleared Export Interchange Transaction Bids; and
(7) Cleared Through Interchange Transactions.

B. The following pricing solution results are communicated to all Market Participants after the posting of the dispatch solution results:

(1) LMPs for each Settlement Location, the marginal Energy component (“MEC”) of the LMP, the Marginal Congestion Component (“MCC”) of the LMP and the Marginal Loss Component (“MLC”) of the LMP for each Settlement Location; and

(2) MCPs for Regulation-Up Service, Regulation-Down Service, Spinning Reserve and Supplemental Reserve for each Reserve Zone.
6.2.2 Real-Time Balancing Market Execution

The Transmission Provider will attempt to execute the RTBM every five (5) minutes for the next Dispatch Interval based on the inputs described above. In the event the Transmission Provider is unable to execute the RTBM or to approve a valid solution for the RTBM, the clearing from the last approved RTBM will carry forward until the approval of a new RTBM.

(1) A simultaneous co-optimization methodology utilizing a SCED algorithm is employed to calculate Resource Dispatch Instructions and clear Regulation-Up Service, Regulation Down Service, Spinning Reserve, Supplemental Reserve, Ramp Capability Up, and Ramp Capability Down, and Uncertainty Reserve to meet the Transmission Provider load forecast and Operating Reserve requirements at minimum costs based upon submitted Offers while respecting Resource operating constraints and transmission constraints as described in Section 3.3.1 of this Attachment AE.

(2) The SCED algorithm includes marginal loss sensitivity factors that approximate the change in marginal system losses for a change in Energy dispatch.

(3) In certain situations, enforcing constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, the Transmission Provider must apply VRLs in SCED.

(4) The co-optimization logic will provide through the Shadow Price calculation, MCPs for Operating Reserve that include lost opportunity costs incurred as a result of Operating Reserve clearing.

(5) Additionally, the Transmission Provider will execute a look-ahead SCED prior to the RTBM SCED process. The Transmission Provider will use the look-ahead SCED results to: (1) anticipate the need to adjust Dispatch Instructions for the current Dispatch Interval to prepare to meet forecasted changes in the load several Dispatch Intervals into the future and (2) determine commitment of Resources that can be on-line within the Operating Hour including Fast Start Resources.

6.2.2.1 Emergency Operations – Capacity Shortage
(1) In addition to the incorporation of the capacity up to Resources’ Maximum Emergency Capacity Operating Limits prior to the Operating Hour as described under Sections 5.1.2(1)(a)(i) and 5.2.2(2)(a) of this Attachment AE, the Transmission Provider may incorporate any remaining emergency capacity limits as needed during the Operating Hour. The Transmission Provider shall continue implementation of emergency procedures which may have been implemented prior to the Operating Hour or shall begin implementation of emergency procedures within the Operating Hour, as needed, in accordance with its authority as Reliability Coordinator.

(a) If there is an actual Operating Reserve shortage during a Dispatch Interval, either on a system-wide or a Reserve Zone basis, the system-wide or Reserve Zone Scarcity Prices will be implemented as specified in Sections 8.3.1 and 8.3.4.2 of this Attachment AE.

(b) If there is a shortage of available capacity to meet Energy requirements on a system-wide, LMPs will be set through Scarcity Pricing procedures as specified in Section 8.3.1 of this Attachment AE.

6.2.2.2 Emergency Operations – Excess Generation

(1) The Transmission Provider will take any or all of the following actions, as time permits, within the Operating Hour to address excess generation conditions on either a system-wide or Reserve Zone basis:

(a) Notify any remaining Resources not cleared for Regulation-Down Service and not notified prior to the Operating Hour that they will be dispatched down to their Minimum Emergency Capacity Operating Limits, Minimum Emergency Discharge Limits, or Maximum Emergency Charge Limits;

(b) De-commit any remaining Resources that were self-committed following the Day-Ahead RUC;

(c) Pro-rata curtail, on a MW basis, any remaining fixed non-firm Import Interchange Transactions;

(d) Pro-rata curtail, on a per MW basis, any fixed firm Import Interchange Transactions;
(e) Reduce Resources with cleared Regulation-Down Service economically, as needed, down to Minimum Emergency Capacity Operating Limits, Minimum Emergency Discharge Limits, or Maximum Emergency Charge Limits;

(f) Coordinate with generation Operators, SPP Balancing Authority Operator and SPP Reliability Coordinator to de-commit generation to meet power balance; and

(g) Commit any MSR that is available for charging.

(2) If actions taken under (1) above are not sufficient to relieve the excess generation condition in any Dispatch Interval either on a system-wide or Reserve Zone basis, LMPs will be set to the lesser of zero (0) or the Offer prices associated with Energy down to the minimum emergency limit, to the extent that the Regulation-Down requirement can be maintained. If the actions under (1) above create a Regulation-Down Service shortage during any Dispatch Interval either on a system-wide or Reserve Zone basis, the MCPs for Regulation-Down Service will reflect Scarcity Prices and LMPs will reflect negative Scarcity Prices.

(3) In parallel with the actions under (1) above, if there is a transmission constraint within a Reserve Zone occurring simultaneously with a Reserve Zone excess capacity event, the Transmission Provider may take any or all of the following additional actions:

(a) Identify and communicate with the Market Participant concerning Resources with greater than a five percent (5%) generation shift factor on the constraint and fixed Import Interchange Transactions with greater than a three percent (3%) transfer distribution factor on constraint;

(b) Issue Transmission Loading Relief (“TLR”) provisions, in accordance with Attachment R, to curtail any Interchange Transactions that may be contributing to the loading;

(c) Commit Resources in the constrained area if they can be re-dispatched with other Resources in the constrained area to relieve constraint without contributing to the excess capacity situation.
6.2.2.3 Congestion Management

The Transmission Provider shall use the following process to coordinate the operations of the RTBM to manage congestion within the SPP Balancing Authority Area and between the SPP Balancing Authority Area and external Balancing Authority Areas:

(a) The Transmission Provider shall submit the Market Flow impact on each Coordinated Flowgate and Reciprocal Coordinated Flowgate to the IDC.

(b) The Transmission Provider shall assign curtailment priorities to the Market Flow on each flowgate in the following priority categories:
   (i) Curtailment priorities for flowgates that have not been defined as a Coordinated Flowgate or a Reciprocal Coordinated Flowgate shall be assigned in accordance with NERC TLR procedures.
   (ii) For Coordinated Flowgates, the Transmission Provider will assign Market Flow in the firm priority up to the firm limit with any excess Market Flow assigned as non-firm network.
   (iii) For Reciprocal Coordinated Flowgates, the Transmission Provider will divide its Market Flows into firm, non-firm network, and non-firm hourly curtailment priorities. The Transmission Provider will first assign Market Flow in the firm priority up to the firm limit, then assign remaining Market Flow in the non-firm network priority up to the non-firm network limit, and finally assign any excess Market Flow as non-firm hourly.

(c) The Market Flow associated with operation of the RTBM shall be determined by the Transmission Provider. For Coordinated Flowgates, any Market Flow from RTBM operation in excess of that assigned to the firm priority shall be assigned a non-firm priority. For Reciprocal Coordinated Flowgates, any Market Flow from RTBM operation in excess of amounts assigned to firm or non-firm network priorities shall be assigned a non-firm hourly priority.

(d) When congestion occurs on a flowgate that requires a TLR event, the IDC will identify the amount of relief required from Market Flows on the Coordinated Flowgate or Reciprocal Coordinated Flowgate.
(e) When congestion occurs on a flowgate that does not require a TLR event, the Transmission Provider shall manage such congestion using its security constrained dispatch software until the flowgate loading is within its applicable operating limits.

(f) The Transmission Provider shall achieve the required reduction in Market Flows provided by the IDC using its security constrained dispatch software in the following order until the desired reduction in Market Flows is achieved:

(i) To the extent that Market Flows are contributing to the constrained condition, the Transmission Provider shall restrict the ability of the market operating system from contributing further to the constrained condition by binding the Coordinated Flowgate or Reciprocal Coordinated Flowgate constraint. The security constrained dispatch of Dispatchable Resources shall continue within each priority level until the Market Flows within that priority level have been reduced to zero or the flowgate constraint is eliminated, whichever comes first.
6.2.3 Real-Time Balancing Market Results

Following execution of the RTBM SCED, the Transmission Provider shall communicate the results to Market Participants.

(1) The following results are communicated to each Market Participant for only its specific Resources prior to the start of the applicable Dispatch Interval:

(a) Resource Dispatch Instructions. The Dispatch Instruction is a MW output target for the end of the applicable Dispatch Interval.


   (i) Cleared Regulation-Up Service MWs represent only those MWs cleared to meet the Regulation-Up Service requirement.

   (ii) Cleared Regulation-Down Service MWs represent only those MWs cleared to meet the Regulation-Down Service requirement.

   (iii) Cleared Spinning Reserve MWs represent the Spinning Reserve MWs cleared to meet the Spinning Reserve requirement and Regulation-Up Service MWs cleared to meet the Spinning Reserve requirement through product substitution as described under Section 3.1.7 of this Attachment AE.

   (iv) Cleared Supplemental Reserve MWs represent the sum of Supplemental Reserve MWs cleared to meet the Supplemental Reserve requirement and Regulation-Up Service MWs and Spinning Reserve MWs cleared to meet the Supplemental Reserve requirement through product substitution as described under Section 3.1.7 of this Attachment AE.

   (v) Cleared Ramp Capability Up MWs represent only those MWs cleared to meet the Ramp Capability Up requirement.

   (vi) Cleared Ramp Capability Down MWs represent only those MWs cleared to meet the Ramp Capability Down requirement.

   (vii) Cleared Uncertainty Reserve MWs represent only those MWs cleared to meet the Uncertainty Reserve requirement.
(2) The following pricing solution results are communicated to all Market Participants after the posting of the dispatch solution and are used for settlement purposes;
(a) LMPs for each Settlement Location, the MCC of LMP for each Settlement Location and the MLC of LMP for each Settlement Location.
(b) MCPs for Regulation-Up Service, Expected Regulation-Up Mileage, Regulation-Down Service, Expected Regulation-Down Mileage, Spinning Reserve and Supplemental Reserve for each Reserve Zone.
8.3.4 Market Clearing Price Calculations

The MCP represents the cost of supplying an increment of Operating Reserve, taking into account lost opportunity cost and is composed of the marginal Operating Reserve costs and marginal costs associated with Operating Reserve scarcity. The Day-Ahead Market and RTBM MCPs at a Reserve Zone for Resources with cleared Regulation-Up Service, Regulation-Down Service, Spinning Reserve and/or Supplemental Reserve in that Reserve Zone are equal to the summation of the applicable Shadow Prices associated with the constraints as described in subsections (1) and (2) below. Calculation of MCPs for Expected Regulation-Up Mileage and Expected Regulation-Down Mileage are calculated as described in subsections (3) and (4) below:

(1) There are six-seven sets of constraints which apply on both a system-wide basis and a Reserve Zone basis:
   (a) A Contingency Reserve plus Regulation-Up constraint is equal to the sum of the Contingency Reserve requirement and the Regulation-Up requirement;
   (b) A Regulation-Up plus Spinning Reserve constraint is equal to the sum of the Regulation-Up requirement and the Spinning Reserve requirement;
   (c) A Regulation-Up constraint is equal to the Regulation-Up requirement;
   (d) A Regulation-Down constraint is equal to the Regulation-Down requirement;
   (e) A Ramp Capability Down constraint is equal to the Ramp Capability Down requirement; and
   (f) A Ramp Capability Up constraint is equal to the Ramp Capability Up requirement; and
   (g) An Uncertainty Reserve constraint is set equal to the Uncertainty Reserve requirement.

(2) Operating Reserve MCPs for each Reserve Zone are calculated as follows:
   (a) The Regulation-Up Service MCP is equal to sum of the Shadow Prices for the system-wide and zonal Regulation-Up constraints, system-wide and zonal Regulation-Up plus Spinning Reserve constraints and the system-wide and zonal Contingency Reserve plus Regulation-Up constraints;
(b) The Spinning Reserve MCP is equal to the sum of the Shadow Prices for the system-wide and zonal Regulation-Up plus Spinning Reserve constraints and the system-wide and zonal Contingency Reserve plus Regulation-Up constraints;

c) The Supplemental Reserve MCP is equal to the sum of the Shadow Prices for the system-wide and zonal Contingency Reserve plus Regulation-Up constraints;

d) The Regulation-Down MCP is equal to the Shadow Price for the system-wide and zonal Regulation-Down constraint;

e) The Ramp Capability Down MCP is equal to the Shadow Price for the system-wide and zonal Ramp Capability Down constraint;

(f) The Ramp Capability Up MCP is equal to the Shadow Price for the system-wide and zonal Ramp Capability Up constraint; and

g) The Uncertainty Reserve MCP is equal to the Shadow Price for the system-wide Uncertainty Reserve constraint.

(3) RTBM MCPs for Expected Regulation-Up Mileage are set equal to the highest Regulation-Up Mileage Offer of all Resources economically cleared to provide Regulation-Up Service in a particular Dispatch Interval. For Resources submitting a Regulation-Up Service dispatch status as described under Section 4.1(11)(c) of this Attachment AE, the cleared amount of Regulation-Up Service MW must be greater than the submitted self-schedule MW in order to be considered economically cleared;

(4) RTBM MCPs for Expected Regulation-Down Mileage are set equal to the highest Regulation-Down Mileage Offer of all Resources economically cleared to provide Regulation-Down Service in a particular Dispatch Interval. For Resources submitting a Regulation-Down Service dispatch status as described under Section 4.1(11)(c) of this Attachment AE, the cleared amount of Regulation-Down Service MW must be greater than the submitted self-schedule MW in order to be considered economically cleared;

(5) In the event a system-wide failure of the RTBM systems results in a loss of the ability to calculate MCPs, RTBM Operating Reserve will continue to be settled
financially under this Tariff based upon estimated MCPs. The Transmission Provider shall notify Market Participants if RTBM Operating Reserve is to be settled using estimated prices.

(a) If the failure of the RTBM systems occurs for twelve (12) Dispatch Intervals or less, the estimated MCPs shall be the most recently calculated MCPs for each affected Reserve Zone and shall be utilized for settlement purposes for each of the Dispatch Intervals in which MCP pricing data is missing.

(b) If the failure of the RTBM systems occurs for more than twelve (12) Dispatch Intervals, the Transmission Provider shall calculate MCPs using mitigated Offers for the RTBM in a manner that reflects, as closely as practicable, the MCPs that would have resulted but for the RTBM systems failure, and shall use such MCPs for settlement purposes for each of the Dispatch Intervals in which MCP pricing data is missing. To the extent that the Transmission Provider is unable to calculate RTBM MCPs, the Transmission Provider shall use the MCPs generated in the Day-Ahead Market for RTBM settlement.

(6) If for any reason a portion of generation and load within the SPP Balancing Authority Area becomes isolated from the rest of the SPP Balancing Authority Area (“Island”), RTBM MCPs will not be calculated and procurement of Operating Reserve within the Island will not be performed.
8.3.4.1 Impact of Violation Relaxation Limits on Security Constrained Economic Dispatch (MCP)

The applicable VRLs impact SCED in the following manner: VRLs are applied independently in the dispatch solution and pricing solution described in Section 3.3.1 of this Attachment AE.

(1) When a Resource capacity, global power balance, Resource ramp, Spinning Reserve, or operating constraint is reached but not exceeded, it is referred to as “binding.” In this state, VRLs are not applicable and MCPs are calculated through the normal SCED solution; and

(2) When a Resource capacity, global power balance, Resource ramp, Spinning Reserve, or operating constraint is exceeded and cannot be resolved, the applicable constraint is relaxed so that SCED can solve. The VRL values applied by SCED in this case act as a cap on the Shadow Price on the applicable Operating Constraint. MCPs are determined by the relaxed SCED solution.
8.3.4.2 Impact of Scarcity Pricing on Locational Marginal Prices and Market Clearing Prices

(1) Demand Curves are applied independently in the dispatch solution and pricing solution described in Section 3.3.1 of this Attachment AE. The Transmission Provider shall use Demand Curves to reflect Scarcity Prices in both the Day-Ahead Market and RTBM during times of Energy and/or Operating Reserve shortages, either on a system-wide and/or Reserve Zone basis.

(2) Scarcity Prices are reflected in MCPs using the following Demand Curves:

(a) The Contingency Reserve Demand Curve Price is applied on both a system-wide basis and zonal basis and is equal to the product of the applicable Contingency Reserve Scarcity Factor, defined in accordance with the Market Protocols, and the sum of the safety-net Energy Offer cap and the Contingency Reserve Offer cap as specified in Section 4.1.1 of this Attachment AE.

(b) The Regulation-Up Service Scarcity Pricing is determined in accordance with the following subparagraphs – 8.3.4.2(2)(b)(i) and (ii) – provided that maximum Regulation-Up Demand Curve Price is equal to the sum of the Regulation-Up Service Offer cap and the Contingency Reserve Offer cap as specified in Section 4.1.1 of this Attachment AE and is applied on a system-wide basis.

(i) If Regulation-Up shortages are caused by insufficient ramping capabilities, then the Regulation-Up Demand Curve Price is equal to the product of the applicable Regulation-Up Scarcity Factor and the Regulation Base Demand Price.

(ii) If Regulation-Up shortages are the result of insufficient capacity, then the Regulation-Up Demand Curve Price is equal to the greater of (a) the marginal Resource clearing cost or (b) the product of the applicable Regulation-Up Scarcity Factor and the Regulation Base Demand Price.

(c) The Regulation-Down Service Scarcity Pricing is determined in accordance with the following subparagraphs – 8.3.4.2(2)(c)(i) and (ii) –
provided that maximum Regulation-Down Demand Curve Price is equal to the sum of the Regulation-Down Service Offer cap and the Contingency Reserve Offer cap as specified in Section 4.1.1 of this Attachment AE and is applied on a system-wide basis.

(i) If Regulation-Down shortages are caused by insufficient ramping capabilities, then the Regulation-Down Demand Curve Price is equal to the product of the applicable Regulation-Down Scarcity Factor and the Regulation Base Demand Price.

(ii) If Regulation-Down shortages are the result of insufficient capacity, then the Regulation-Down Demand Curve Price is equal to the greater of (a) the marginal Resource clearing cost and (b) the product of the applicable Regulation-Down Scarcity Factor and the Regulation Base Demand Price.

(d) Ramp Capability Up – The Transmission Provider calculates and posts Ramp Capability Up Scarcity Pricing in accordance with the following rules:

(i) The maximum Scarcity Price is calculated as the average cost per MW for all eligible Resources to recover their qualified cold Start-Up Offer, No-Load Offer, and Energy at minimum cost at their Maximum Normal Operating Limit. Eligible Resources are Resources which offer a cold start-up time of 10 minutes or less, a Minimum Run Time of 60 minutes or less, and are not on outage. The maximum Scarcity Price is equal to the cold Start-Up Offer plus the product of the Minimum Run Time and the No-Load Offer plus the Energy at minimum cost all divided by the Resource’s Maximum Normal Capacity Operating Limit or Maximum Discharge Limit as applicable.

(ii) The maximum Scarcity Price will be calculated each month using the previous three months offer data.

(iii) The Demand Curve levels for Ramp Capability Up will be equal to:

1. Shortages up to or equal to 5% of the requirement will equal, to the nearest dollar, 1/6 of the maximum Scarcity Price.
2. Shortages greater than 5% but less than or equal to 10% of the requirement will equal, to the nearest dollar, 1/3 of the maximum Scarcity Price.

3. Shortages greater than 10% but less than or equal to 15% of the requirement will equal, to the nearest dollar, 1/2 of the maximum Scarcity Price.

4. Shortages greater than 15% but less than or equal to 25% of the requirement will equal, to the nearest dollar, 2/3 of the maximum Scarcity Price.

5. Shortages greater than 25% but less than or equal to 40% of the requirement will equal, to the nearest dollar, 5/6 of the maximum Scarcity Price.

6. Shortages greater than 40% of the requirement will equal, to the nearest dollar, the maximum Scarcity Price.

(iv) The minimum amount for the Ramp Capability Up Demand Curve prices will be limited to $10.

(e) Ramp Capability Down – The Transmission Provider calculates and posts Ramp Capability Down Scarcity Pricing in accordance with the following rules:

(i) The maximum Scarcity Price is calculated as the average cost per MW for all eligible Resources to recover their qualified cold Start-Up Offer, No-Load Offer, and Energy at minimum cost at their Maximum Normal Operating Limit. Eligible Resources are Resources which offer a cold Start-Up Time of 10 minutes or less, a Minimum Run Time of 60 minutes or less, and are not on outage. The maximum Scarcity Price is equal to the cold Start-Up Offer plus the product of the Minimum Run Time and the No-Load Offer plus the Energy at minimum cost all divided by the Resource’s Maximum Normal Capacity Operating Limit or Maximum Discharge Limit as applicable.

(ii) The maximum Scarcity Price will be calculated each month using the previous three months offer data.

(iii) The Demand Curve levels for Ramp Capability Down will be equal to:
1. Shortages up to or equal to 5% of the requirement will equal, to the nearest dollar, $1/6$ of the maximum Scarcity Price.

2. Shortages greater than 5% but less than or equal to 10% of the requirement will equal, to the nearest dollar, $1/3$ of the maximum Scarcity Price.

3. Shortages greater than 10% but less than or equal to 15% of the requirement will equal, to the nearest dollar, $1/2$ of the maximum Scarcity Price.

4. Shortages greater than 15% but less than or equal to 25% of the requirement will equal, to the nearest dollar, $2/3$ of the maximum Scarcity Price.

5. Shortages greater than 25% but less than or equal to 40% of the requirement will equal, to the nearest dollar, $5/6$ of the maximum Scarcity Price.

6. Shortages greater than 40% of the requirement will equal, to the nearest dollar, the maximum Scarcity Price.

(iv) The minimum amount for the Ramp Capability Down Demand Curve prices will be limited to $0$.

(f) Uncertainty Reserve – The Transmission Provider calculates and posts Uncertainty Reserve Scarcity Pricing in accordance with the following rules:

1. The Uncertainty Reserve Demand Curve prices are determined by applying a factor to the Regulation Base Demand Price such that the magnitude of the Uncertainty Reserve Demand Curve price is less than the Regulation Base Demand Price.

2. The Demand Curve levels for Uncertainty Reserve will be equal to:

   a. Shortages up to or equal to 5% of the requirement will equal, to the nearest dollar, $0.05$ times the Regulation Base Demand Price.

   b. Shortages greater than 5% but less than or equal to 10% of the requirement will equal, to the nearest dollar, $0.35$ times the Regulation Base Demand Price.
c. Shortages greater than 10% but less than or equal to 15% of the requirement will equal, to the nearest dollar, 0.55 times the Regulation Demand Price.

d. Shortages greater than 15% but less than or equal to 20% of the requirement will equal, to the nearest dollar, 0.70 times the Regulation Demand Price.

e. Shortages greater than 20% of the requirement will equal, to the nearest dollar, 0.95 times the Regulation Demand Price.

3. The minimum amount for the Uncertainty Demand Curve prices will be limited to $10.

(3) Scarcity Prices will be reflected in LMPs when serving an incremental MW of energy worsens the Operating Reserve capacity shortage condition.

(4) During Operating Reserve shortage conditions on a system wide basis and/or zonal basis, Market Clearing Prices are impacted by Demand Curves as follows:

(a) If there is a system-wide shortage of Contingency Reserve, no shortage of Regulation-Up or Regulation-Down, and all zonal minimum requirements have been met:

(i) the system-wide Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(ii) the zonal Regulation-Up plus Contingency Reserve constraint Shadow Price is calculated normally and does not reflect the Contingency Reserve Demand Curve Price;

(iii) the Regulation-Up and Regulation-Down constraint Shadow Prices are calculated normally and do not reflect the Regulation-Up or Regulation-Down Demand Curve Prices;

(iv) the Supplemental Reserve MCP shall reflect the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE; and

(v) the Spinning Reserve MCP and the Regulation-Up MCP shall also reflect the Contingency Reserve Demand Curve Price through the
calculations described under Sections 8.3.4(2)(b) and 8.3.4(2)(a) of this Attachment AE respectively.

(b) If there is a system-wide shortage of Contingency Reserve, a shortage of Regulation-Up, no shortage of Regulation-Down, and all zonal minimum requirements have been met:

(i) the system-wide Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(ii) the system-wide Regulation-Up constraint Shadow Price is set equal to the Regulation-Up Demand Curve Price;

(iii) the zonal Regulation-Up plus Contingency Reserve constraint Shadow Price is calculated normally and does not reflect the Contingency Reserve Demand Curve Price;

(iv) the Regulation-Down constraint Shadow Price is calculated normally and does not reflect the Regulation-Down Demand Curve Price;

(v) the Supplemental Reserve MCP shall reflect the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(vi) the Spinning Reserve MCP shall also reflect the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(b) of this Attachment AE; and

(vii) the Regulation-Up MCP shall reflect the summation of the Contingency Reserve Demand Curve Price and the Regulation-Up Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE.

(c) If there is a system-wide shortage of Contingency Reserve, no shortage of Regulation-Up or Regulation-Down, and zonal minimum requirements cannot not be met:
(i) the system-wide Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(ii) the zonal Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(iii) the Regulation-Up and Regulation-Down constraint Shadow Prices are calculated normally and do not reflect the Regulation-Up or Regulation-Down Demand Curve Prices;

(iv) the Supplemental Reserve MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(v) the Supplemental Reserve MCP in all Reserve Zones in which the minimum requirements have not been met shall reflect the summation of the system-wide Contingency Reserve Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(vi) the Spinning Reserve MCP and Regulation-Up MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the Contingency Reserve Demand Curve Price through the calculations described under Sections 8.3.4(2)(b) and 8.3.4(2)(a) of this Attachment AE respectively; and

(vii) the Spinning Reserve MCP and Regulation-Up MCPs in all Reserve Zones in which the minimum requirements have not been met shall reflect the summation of the system-wide Contingency Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculations described under Sections 8.3.4(2)(b) and 8.3.4(2)(a) of this Attachment AE, respectively.
(d) If there is a system-wide shortage of Contingency Reserve, a shortage of Regulation-Up, no shortage of Regulation-Down, and zonal minimum requirements cannot not be met:

(i) the system-wide Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(ii) the zonal Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(iii) the Regulation-Up constraint Shadow Price is set equal to the Regulation-Up Demand Curve Price;

(iv) the Regulation-Down constraint Shadow Price is calculated normally and does not reflect the Regulation-Down Demand Curve Price;

(v) the Supplemental Reserve MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the Contingency Reserve Demand Curve price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(vi) the Spinning Reserve MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the Contingency Reserve Demand Curve price through the calculations described under Section 8.3.4(2)(b) of this Attachment AE;

(vii) the Regulation-Up MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the summation of the Regulation-Up Demand Curve Price and the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE;

(viii) the Supplemental Reserve MCP in all Reserve Zones in which the minimum requirements have not been met shall reflect the summation of the system-wide Contingency Reserve Demand
Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(ix) the Spinning Reserve MCP in all Reserve Zones in which the minimum requirements have not been met shall reflect the summation of the system-wide Contingency Reserve Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(b) of this Attachment AE; and

(x) the Regulation-Up MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the summation of the Regulation-Up Demand Curve Price, the system-wide Contingency Reserve Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE.

(e) If there is a system-wide shortage of Regulation-Up, no shortage of Regulation-Down, no shortage of Contingency Reserve, and all zonal minimum requirements have been met:

(i) the Regulation-Up constraint Shadow Price is set equal to the Regulation-Up Demand Curve Price;

(ii) the Regulation-Up plus Contingency Reserve constraint Shadow Price is calculated normally and does not reflect the Contingency Reserve Demand Curve Price;

(iii) the Supplemental Reserve MCP and Spinning Reserve MCP shall not reflect the Contingency Reserve Demand Curve Price through the calculation described under Sections 8.3.4(2)(c) and 8.3.4(b) of this Attachment AE respectively; and

(iv) the Regulation-Up MCP shall reflect the Regulation-Up Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE.
(f) If there is a system-wide shortage of Regulation-Down, no shortage of Regulation-Up, no shortage of Contingency Reserve, and all zonal minimum requirements have been met:

(i) the Regulation-Down constraint Shadow Price is set equal to the Regulation-Down Demand Curve Price;

(ii) the Regulation-Up plus Contingency Reserve constraint Shadow Price is calculated normally and does not reflect the Contingency Reserve Demand Curve Price;

(iii) the Regulation-Up constraint Shadow Price is calculated normally and does not reflect the Regulation-Up Demand Curve Price;

(iv) the Supplemental Reserve MCP and Spinning Reserve MCP shall not reflect the Contingency Reserve Demand Curve Price through the calculation described under Sections 8.3.4(2)(c) and 8.3.4(b) of this Attachment AE respectively;

(v) the Regulation-Up MCP shall not reflect the Regulation-Up Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE; and

(vi) the Regulation-Down MCP shall reflect the Regulation-Down Demand Curve Price through the calculation described under Section 8.3.4(2)(d) of this Attachment AE.

(g) If there is a system-wide shortage of Ramp Capability Up, the Ramp Capability Up MCP will be set equal to the Ramp Capability Up Demand Curve price. The Ramp Capability Up Demand Curve price will be reflected in the LMP.

(h) If there is a system-wide shortage of Ramp Capability Down, the Ramp Capability Down MCP will be set equal to the Ramp Capability Down Demand Curve price. The Ramp Capability Down Demand Curve price will be reflected in the LMP.

(i) If there is a system-wide shortage of Uncertainty Reserve, the Uncertainty Reserve MCP will be set equal to the applicable Uncertainty Reserve
Demand Curve Price. The Uncertainty Reserve Demand Curve price will be reflected in the LMP.

8.3.4.3 Operating Reserve Scarcity Factors

The Transmission Provider calculates and posts Contingency Reserve Scarcity Factors, Regulation-Up Scarcity Factors and Regulation-Down Scarcity Factors as described below.

(1) The Contingency Reserve Scarcity Factor varies based on the MW amount of Contingency Reserve shortage. The Contingency Reserve shortage MW values that result in changes to the scarcity price values are calculated by the Transmission Provider based on the projected Most Severe Single Contingency (MSSC) for the Operating Day in accordance with the following rules:

a. For Contingency Reserve shortages less than or equal to one-half of the SPP Reserve Sharing Group Contingency Reserve requirement above the MSSC, the Reserve Scarcity Factor will be set to 0.25.

b. For Contingency Reserve Shortages greater than one-half the SPP Reserve Sharing Group Contingency Reserve requirement above the MSSC but less than or equal to SPP Reserve Sharing Group Contingency Reserve requirement above the MSSC, the Contingency Reserve Scarcity Factor will be set to 0.5.

c. For Contingency Reserve Shortages greater than the SPP Reserve Sharing Group Contingency Reserve requirement above the MSSC, the Contingency Reserve Scarcity Factor will be set to 1.

(2) The Regulation-Up Scarcity Factor varies based on the MW amount of Regulation-Up shortage. The Regulation-Up shortage MW values that result in changes to the Scarcity Price values are calculated by the Transmission Provider using historical Regulation-Up deployment data in accordance with the following rules:
a. For Regulation-Up reserve shortages less than or equal to 30 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 1.

b. For Regulation-Up reserve shortages greater than 30 percent but less than or equal to 50 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 2.

c. For Regulation-Up reserve shortages greater than 50 percent but less than or equal to 70 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 3.

d. For Regulation-Up reserve shortages greater than 70 percent but less than or equal to 80 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 4.

e. For Regulation-Up reserve shortages greater than 80 percent but less than or equal to 90 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 5.

f. For Regulation-Up Reserve shortages greater than 90 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Pricing level will be set to the maximum Scarcity Pricing level described in Section 8.3.4.2(2)(b).

(3) The Regulation-Down Scarcity Factor varies based on the MW amount of Regulation-Down shortage. The Regulation-Down shortage MW values that result in changes to the Scarcity Price values are calculated by the Transmission Provider using historical Regulation-Down deployment data in accordance with the following rules:

a. For Regulation-Down reserve shortages less than 30 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 1.
b. For Regulation-Down reserve shortages greater than 30 but less than or equal to 50 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 2.

c. For Regulation-Down reserve shortages greater than 50 but less than or equal to 70 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 3.

d. For Regulation-Down reserve shortages greater than 70 but less than or equal to 80 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 4.

e. For Regulation-Down reserve shortages greater than 80 but less than or equal to 90 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 5.

f. For Regulation-Down reserve shortages greater than 90 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Pricing level will be set to the maximum Scarcity Pricing level described in Section 8.3.4.2(2)(c) of this Attachment AE.
8.3.4.4 Regulation Base Demand Price

On a monthly basis, the Transmission Provider calculates and posts a Regulation Base Demand Price as a function of the cost to commit a Resource to provide ramp or capacity to the market in accordance with the following rules:

(1) Regulation Base Demand Price is the average cost per MW for all Resources to recover their qualified cold start-up, no-load, and Energy costs at their Minimum Normal Operating Limit or Minimum Discharge Limit, as applicable.

(2) For each interval and Resource, a cold start-up time must be less than or equal to 10 minutes and the Real-Time commitment status must be Market, Reliability, or Self for the Resource costs to qualify for inclusion in the calculation.

(3) By interval and Resource, the average cost per MW is based on the costs (cold start-up, no-load, and Energy) that would be incurred at the minimum load and minimum run time from three months of historical offer data.

The Transmission Provider may re-calculate the Regulation Base Demand Price more frequently than once a month as needed in order to reflect the operational cost of Resources if projected to be significantly different than historical based offer data.
8.5.9  Day-Ahead Make Whole Payment Amount

(1) The Day-Ahead make whole payment amount is a payment to an Asset Owner and is calculated for each Resource with an associated Day-Ahead Market Commitment Period that was committed by the Transmission Provider including commitments from the Multi-Day Reliability Assessment as defined under Section 4.5.3 of this Attachment AE. Asset Owners of Resources previously committed by a local transmission operator to address a Local Emergency Condition are eligible to receive a Day-Ahead Market make whole payment if such commitment is included in the Day-Ahead Market; except that, if the Market Monitor determines such Resources were selected in a discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, and such Resources were affiliated with the local transmission operator, then such Resources are not eligible to receive a Day-Ahead Market make whole payment. A payment is made to an Asset Owner when a Resource’s costs are greater than the Day-Ahead Market revenues received during the Resource’s Day-Ahead Market make whole payment eligibility period. The make whole payment is equal to this difference between those costs and revenues.

(2) A Resource’s Day-Ahead Market make whole payment eligibility period is equal to a Resource’s Day-Ahead Market Commitment Period except as defined herein. For Resources with an associated Day-Ahead Market Commitment Period that begins in one Operating Day and ends in the next Operating Day, two (2) Day-Ahead Market make whole payment eligibility periods are created. The first period begins in the first Operating Day in the hour that the Day-Ahead Market Commitment Period begins and ends in the last hour of the first Operating Day. The second period begins in the first hour of the next Operating Day and ends in the last hour of the Day-Ahead Market Commitment Period.

(3) The following cost recovery rules apply to each Day-Ahead Market make whole payment eligibility period. Offer costs are calculated using the Day-Ahead Market Offer prices in effect at the time the commitment decision was made except under the situation described under Section (b)(iiv) below.
(a) There may be more than one Day-Ahead Market make whole payment eligibility period for a Resource in a single Operating Day for which a charge or payment is calculated. A single Day-Ahead Market make whole payment eligibility period is contained within a single Operating Day.

(b) A Resource’s Day-Ahead Market commitment level offer costs include Start-Up Offer, Transition State Offer, and RUC remainder amount (as described in Section 8.5.9(3)(b)(v) of this Attachment AE) for a Day-Ahead Market make whole payment eligibility period in which that Resource is committed with a Day-Ahead Market Resource Offer commitment status under Section 4.1(10)(a), (b) or (c) of this Attachment AE, including commitments from the Multi-Day Reliability Assessment as described under Section 4.5.3 of this Attachment AE. The commitment level cost eligible for recovery is calculated by subtracting all Start-Up Offer cost and Transition State Offer cost associated with a Day-Ahead Market Resource Offer commitment status as described under Sections 4.1(10)(a) of this Attachment AE from all eligible commitment level Offer costs required to execute the Day-Ahead schedule associated with the Day-Ahead Market make whole payment eligibility period. The resulting difference represents either a charge or a payment and is a cost component when determining a Day-Ahead Market make whole payment.

(i) In any Day-Ahead Market make whole payment eligibility period for which the Day-Ahead Market SCUC algorithm did not consider the Resource’s Start-Up Offer in the original commitment decision, except Day-Ahead Start-Up Offer costs associated with the commitments made under Sections 4.5 and 5.1.2(1)(b) of this Attachment AE that caused an additional scheduled start, the Resource’s Start-Up Offer shall equal zero.

(ii) A Resource’s Day-Ahead Market Start-Up Offer cost is not eligible for recovery in the following Day-Ahead Market make whole payment eligibility periods:
(1)  For any Day-Ahead make whole payment eligibility period for which a Resource is a Synchronized Resource prior to this commitment period at a time one (1) hour prior to that Resource’s Day-Ahead Market Commit Time in addition to the Resource’s Sync-To-Min Time unless the Day-Ahead Market make whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the one (1) hour in addition to the Resource’s Sync-To-Min Time; or

(2)  For any Day-Ahead make whole payment eligibility period for which a Staggered Start Resource is a Synchronized Resource prior to this commitment period at a time two (2) hours prior to that Resource’s Day-Ahead Market Commit Time in addition to the Resource’s Sync-To-Min Time unless the Day-Ahead Market make whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the two (2) hours in addition to the Resource’s Sync-To-Min Time.

(iii)  When a RUC commitment is made at a point in time after the existing Day-Ahead Market commitment was made, but the RUC commitment is scheduled for a time adjacent and prior to the existing Day-Ahead Market commitment, the cost considered at the point of adjacency between the RUC and Day-Ahead Market commitments will be allocated between the two commitments for make whole payment purposes as described in (1) and (2) below.

(1)  The cost allocated to the RUC make whole payment will not be greater than the difference between: (a) the Day-Ahead Market Start-Up Offer and Transition State Offer costs at the adjacency point of the RUC and Day-Ahead Market commitment; and (b) Day-Ahead Market Start-Up
Offer and Transition State Offer costs associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(a) of this Attachment AE commitment at the adjacency point.

(2) The commitment level cost in the Day-Ahead Market make whole payment is reduced by the non-negative cost allocated to the RUC make whole payment.

(iv) A Resource’s Day-Ahead Market Transition State Offer costs for a Day-Ahead Market commitment are eligible for recovery in the Day-Ahead Market make whole payment eligibility period except when the Day-Ahead Market SCUC algorithm did not consider the Resource’s Transition State Offer in the Day-Ahead commitment decision unless Transition State Offers costs are associated with manual commitments as described under Sections 4.5.2 and 5.1.2 of this Attachment AE.

(v) As described under Section 8.6.5(3)(g) of this Attachment AE, to the extent that the full amount of the eligible RTBM Start-Up cost is not accounted for in the adjacent RUC make whole payment eligibility period, any remaining RTBM Start-Up cost is carried forward for recovery in the adjacent Day-Ahead make whole payment eligibility period.

(vi) When a Resource loses eligibility to recover a Day-Ahead Market Start-Up Offer cost for the reason described in Section 8.5.9(3)(b)(ii)(1) of this Attachment AE, to prevent overstatement avoided costs, the commitment level cost is adjusted by the lesser of: (a) the Resource’s Start-Up Offer cost and Transition State Offer cost associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(a) of this Attachment AE commitments; or (b) the ineligible Day-Ahead Market Start-Up Offer cost.
For each Day-Ahead Market make whole payment eligibility period within an Operating Day, a Resource’s eligible Start-Up cost is divided by the lesser of (1) the Resource’s applicable Minimum Run Time rounded down to the nearest hour or (2) twenty-four (24) hours, to achieve an hourly proration for the purpose of allocating Start-Up costs across adjacent Day-Ahead commitments.

(1) If the number of participating hours of a Day-Ahead Market make whole payment eligibility period meets or exceeds the duration of the divisor as described in (vii) above, the full cost of the Start-Up Offer is included in the commitment level cost for the Day-Ahead Market make whole payment eligibility period.

(2) If the number of participating hours of a Day-Ahead Market make whole payment eligibility period is less than the duration of the divisor as described in (vii) above, the hourly proration is multiplied by the number of participating hours to achieve a single Start-Up Offer amount to be included in the commitment level cost for that Day-Ahead Market make whole payment eligibility period. Any remaining Day-Ahead Market Start-Up Offer cost will be included in the commitment level cost for the following and adjacent Day-Ahead Market make whole payment eligibility period in the next Operating Day.

(c) For an MCR, additional costs or revenues are incurred when the Resource has cleared Contingency Reserve, Ramp Capability Up, or Ramp Capability Down, or Uncertainty Reserve in the Day-Ahead Market and must buy back that position in Real-Time at an average hourly Real-Time MCP. These costs or revenues will be considered as an adjustment when determining a Day-Ahead Market make whole payment. These costs or revenues must be incurred during a time period in the Day-Ahead Market.
make whole payment eligibility period in which the Resource is transitioning in Real-Time due to a Day-Ahead scheduled transition that is not forced by the Resource Offer. The Market Participant may also be eligible for adjustments to a Day-Ahead Market make whole payment for costs or revenues incurred during transition if the Resource is transitioning in Real-Time in response to a local transmission operator to address a Local Emergency Condition, (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE) then such Resources are not eligible to receive an adjustment to a Day-Ahead make whole payment for these costs or revenues. In such cases, the adjustment is equal to the Real-Time MCP multiplied by the Day-Ahead Market cleared Contingency Resource, Ramp Capability Up, or Ramp Capability Down, or Uncertainty Reserve MW amounts. Recovery of these costs of revenues is limited to the dispatch interval time periods defined by the Transition State Time submitted in the Resource Offer.

(d) If a Resource’s self-commitment period is less than the Resource’s Minimum Run Time, the Transmission Provider will relax the Resource’s Minimum Run Time to equal the self-commit period.

(e) If a Resource is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE in the Day-Ahead Market, the Resource will be eligible to recover applicable recurring costs as defined in Section 8.5.9(4)(a) of this Attachment AE for that period in the Day-Ahead Market make whole payment eligibility period.

(4) The payment to each Asset Owner for each eligible Settlement Location for a given Day-Ahead Market make whole payment eligibility period is calculated as follows:

\[
\text{Day-Ahead Make Whole Payment Amount} = \text{Maximum of } [\text{Either Zero or Sum of } ((\text{Day-Ahead Make Whole Payment Cost Amount in the Day-Ahead Market Make Whole Payment Eligibility Period}) + (\text{Day-Ahead Make Whole Payment Revenue Amount in the)}]
\]
(a) An Asset Owner’s Day-Ahead Make Whole Payment Cost Amount for each eligible Resource is equal to the sum for all hours in the Day-Ahead Market Make Whole Payment Eligibility Period of:

(i) Day-Ahead Market No-Load Offer,

(ii) Energy cost associated with cleared Resource Energy, including MSRs providing a market service, from Resource Energy Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Resource Energy by the cost of such Energy as calculated from the Resource’s Day-Ahead Market Energy Offer Curve,

(iii) Regulation-Up Service cost associated with cleared Regulation-Up Service from Regulation-Up Service Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Up Service by the cost of such Regulation-Up Service as calculated from the Resource’s Day-Ahead Market Regulation-Up Service Offer,

(iv) Regulation-Down Service cost, associated with cleared Regulation-Down Service from Regulation-Down Service Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Down Service by the cost of such Regulation-Down Service as calculated from the Resource’s Day-Ahead Market Regulation-Down Service Offer,

(v) Spinning Reserve cost, associated with: (1) cleared Spinning Reserve from Spinning Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Spinning Reserve by the Day-Ahead Spinning Reserve offer; and (2) cleared Spinning Reserve from Regulation-Up Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Up for Spinning Reserve by the
Day-Ahead Regulation-Up capability offer to the extent that Regulation-Up Service was cleared to meet the Spinning Reserve requirement. Such costs shall exclude Spinning Reserve and Regulation-Up costs associated with an MCR during a Day-Ahead Market scheduled transition time when the MCR is transitioning in the Real-Time Balancing Market,

(vi) Supplemental Reserve cost, associated with: (1) cleared Supplemental Reserve from Supplemental Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Supplemental Reserve by the Day-Ahead Supplemental Reserve Offer; (2) cleared Supplemental Reserve from Spinning Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Spinning Reserve for Supplemental Reserve by the Day-Ahead Spinning Reserve offer to the extent that Spinning Reserve was cleared to meet the Supplemental Reserve requirement; and (3) cleared Supplemental Reserve from Regulation-Up Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Up for Supplemental Reserve by the Day-Ahead Regulation-Up capability offer to the extent that Regulation-Up Service was cleared to meet the Supplemental Reserve requirement. Such costs shall exclude Supplemental Reserve, Spinning Reserve, and Regulation-Up costs associated with an MCR during a Day-Ahead Market scheduled transition time when the MCR is transitioning in the Real-Time Balancing Market,

(vii) Day-Ahead Potential Unused Regulation-Up Mileage Make Whole Payment as calculated under Section 8.6.19(1)(b) of this Attachment AE, and
(viii) Day-Ahead Potential Unused Regulation-Down Mileage Make Whole Payment as calculated under Section 8.6.20(1)(b) of this Attachment AE,

(ix) Day-Ahead Combined Cycle Spinning Reserve Adjustment which is a charge or payment, as described in Section 8.5.9(3)(c) of this Attachment AE, associated with an MCR, which is not eligible to clear Spinning Reserve in RTBM during a Real-Time transition between configurations which was scheduled in a Day-Ahead Market make whole payment eligibility period, and

(x) Day-Ahead Combined Cycle Supplemental Reserve Adjustment which is a charge or payment, as described in Section 8.5.9(3)(c) of this Attachment AE, associated with an MCR, which is not eligible to clear Supplemental Reserve in RTBM during a Real-Time transition between configurations which was scheduled in a Day-Ahead Market make whole payment eligibility period.

(b) An Asset Owner’s Day-Ahead Make Whole Payment Revenue Amount for each eligible Resource that is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE is equal to the sum for all hours in the Day-Ahead Market Make Whole Payment Eligibility Period of:

(i) Energy revenue associated with cleared Resource Energy, and MSRs providing a market service, from Resource Energy Offers as described under Section 5.1.3 of this Attachment AE, calculated by multiplying Resource Energy by Day-Ahead LMP at that Resource Settlement Location, and

(ii) The sum of the revenues calculated under Section 8.5.2, 8.5.3, 8.5.4, 8.5.26, 8.5.29, 8.6.19(1) and 8.6.20(1) of this Attachment AE for that eligible Resource.

(c) An Asset Owner’s Day-Ahead Make Whole Payment Commitment Cost Amount for each eligible Resource in the Day-Ahead Market Make Whole Payment Eligibility Periods is equal to:
(i) Day-Ahead Market Start-Up Offer or any RUC remainder amount as described in Section 8.6.5(3)(f) of this Attachment AE, plus

(ii) Day-Ahead Transition State Offer (for an MCR), plus

(iii) Any amount of Start-Up costs where the Resource loses eligibility to recover as described in Section 8.5.9(3)(b)(v) of this Attachment AE, minus

(iv) Any amount of shared Start-Up costs between Day-Ahead Market and RUC make whole payment eligibility periods as described in Section 8.5.9(3)(b)(ii) of this Attachment AE, minus

(v) All Start-Up and Transition State Offer costs associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(a) of this Attachment AE.
8.5.29 Day-Ahead Uncertainty Reserve Amount

A Day-Ahead Market payment for cleared Uncertainty Reserve will be calculated at each Settlement Location for each Asset Owner for each hour as follows:

Day-Ahead Uncertainty Reserve Hourly Amount =

\[(\text{Day-Ahead MCP}) \times (\text{Day-Ahead Cleared Uncertainty Reserve Hourly Quantity})] \times (-1)

(1) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Uncertainty Reserve associated with the Reserve Zone in which the applicable Resource is located.

(2) An Asset Owner’s Day-Ahead Cleared Uncertainty Reserve Hourly Quantity is the MW quantity associated with cleared Uncertainty Reserve Offers as described under Section 5.1.3 of this Attachment AE.
8.5.30 Day-Ahead Uncertainty Reserve Distribution Amount

A Day-Ahead Market charge for Uncertainty Reserve procurement costs calculated under Section 8.5.29 of this Attachment AE will be calculated at each Reserve Zone for each Asset Owner for each hour as follows:

Day-Ahead Uncertainty Reserve Hourly Distribution Amount =

[(Day-Ahead Uncertainty Reserve Obligation) * (Day-Ahead Uncertainty Reserve Procurement Rate)]

(1) An Asset Owner’s Day-Ahead Uncertainty Reserve Obligation in each Reserve Zone is equal to the system wide total of all cleared Uncertainty Reserve multiplied by the Asset Owner Reserve Zone Load Ratio Share, adjusted up or down to account for any Bilateral Settlement Schedules for Uncertainty Reserve.

(2) For a Reserve Zone that clears more Uncertainty Reserve than the sum of Asset Owners’ Day-Ahead Uncertainty Reserve Obligations for that Reserve Zone, the zone is deemed an exporting zone and the Day-Ahead Uncertainty Reserve Procurement Rate is equal to the Uncertainty Reserve MCP for that Reserve Zone.

(3) For a Reserve Zone that clears less Uncertainty Reserve than the sum of Asset Owners’ Day-Ahead Uncertainty Reserve Obligations for that Reserve Zone, the Day-Ahead Uncertainty Reserve Procurement Rate is as follows:

Day-Ahead Uncertainty Reserve Procurement Rate =

{(Reserve Zone MCP * Total of cleared Uncertainty Reserve for that Reserve Zone) + [(Weighted Average MCP of all Exporting Zones) * (Sum of Asset Owners’ Day-Ahead Uncertainty Reserve Obligations for that Reserve Zone - Total of cleared Uncertainty Reserve for that Reserve Zone)]} / (Sum of Asset Owners’ Day-Ahead Uncertainty Reserve Obligations for that Reserve Zone).
8.6.5 Reliability Unit Commitment Make Whole Payment Amount

(1) Asset Owners of Resources committed by the Transmission Provider during the RUC processes, are eligible to receive a RUC make whole payment. Asset Owners of Resources committed by a local transmission operator during the RUC processes to address a Local Emergency Condition are eligible to receive a RUC make whole payment, except that, if the Market Monitor determines such Resources were selected in a discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, and such Resources were affiliated with the local transmission operator, then such Resources are not eligible to receive a RUC make whole payment. A RUC make whole payment is made to the Asset Owner when the sum of a Resource’s costs associated with actual Energy and cleared RTBM Operating Reserve is greater than the RTBM revenues received over the Resource’s RUC make whole payment eligibility period. Recovery of such compensation shall be collected in accordance with Section 8.6.7 of this Attachment AE.

(2) A Resource’s RUC make whole payment eligibility period is equal to the set of a Resource’s contiguous RUC Commitment Periods and adjacent Day-Ahead Market commitment periods except:

(a) For Resources with a set of contiguous Day-Ahead and RUC Commitment Periods that continue from one Operating Day to the next Operating Day, a RUC make whole payment eligibility period is created for each Operating Day in which there is a RUC commitment. A RUC make whole payment eligibility period is created for each Operating Day with a RUC commitment. The start of a RUC make whole payment eligibility period is the later of (1) beginning of the Operating Day or (2) the beginning of the set of contiguous Day-Ahead Market and RUC commitments. The end of a RUC make whole payment eligibility period is the earlier of (1) the end of the set of contiguous Day-Ahead Market and RUC commitments or (2) the end of the Operating Day; or

(b) For an MCR that cleared in the Day-Ahead Market and was transitioned to a different configuration in Real-Time by the Transmission Provider or by
a local transmission operator to address a Local Emergency Condition (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE), the costs in the intervals preceding the RUC commitment for the purpose of buying back Operating Reserve products while the Resource transitions to the RUC committed configuration, as defined by the Transition State Time of the Resource’s offer parameters in Section 4.1(9) of this Attachment AE, are included in the RUC make whole payment calculation.

(3) The following cost recovery rules apply to each RUC make whole payment eligibility period. Resource production costs are calculated using the RTBM Offer prices in effect at the time the commitment decision was made for start-up, transitions, no-load, and minimum-energy; and the RTBM Offer price in effect at the solving of a dispatch interval for the Energy above minimum energy, Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve.

(a) If the Transmission Provider cancels a Commitment Instruction prior to the start of the associated RUC make whole payment eligibility period, the Asset Owner will receive reimbursement for a time-based pro-rata share of the Resource’s RTBM Start-Up Offer unless precluded by Section 8.6.5(3)(e)(i) of this Attachment AE. Asset Owners may request additional compensation through submittal of actual cost documentation to the Transmission Provider. The Transmission Provider will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

(b) In order to receive the full amount of Start-Up Offer recovery within a RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in at least one Dispatch Interval in the RUC make whole payment eligibility period.

(c) In order to receive recovery of No-Load Offer costs in any Dispatch Interval in the RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in that Dispatch Interval.
(d) There may be more than one RUC make whole payment eligibility period for a Resource in a single Operating Day. A single RUC make whole payment eligibility period is contained within a single Operating Day.

(e) A Resource’s RUC commitment level offer costs include Start-Up Offer cost and Transition State Offer cost for a RUC make whole payment eligibility period in which that Resource is committed with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a), (b) or (c) of this Attachment AE. The commitment level cost eligible for recovery is calculated by subtracting: (1) all Start-Up Offer cost and Transition State Offer cost associated with the schedule created by combining all Day-Ahead Market commitments with a Day-Ahead Market Resource Offer commitment status as defined under Section 4.1(10)(a), (b) or (c) of this Attachment AE contained within a RUC make whole payment eligibility period and all RUC commitments that are associated with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a) of this Attachment AE within a RUC make whole payment eligibility period; from (2) all eligible commitment level offer costs associated with the final Resource schedule in a RUC make whole payment eligibility period. The resulting difference can represent a charge or a payment and is considered as an adjustment when determining a RUC make whole payment.

(i) Except for an MCR that is committed by RUC in a different configuration than in the Day-Ahead Market, when a RUC make whole payment eligibility period is created after a Day-Ahead make whole payment eligibility period and is adjacent and preceding that Day-Ahead make whole payment eligibility period where the Day-Ahead Start-Up Offer Amount defined in Section 8.5.9(3)(b)(i) of this Attachment AE was considered, the Day-Ahead Start-up Offer Amount is used in place of the RUC Start-up costs.
(ii) In any RUC make whole payment eligibility period for which the RUC SCUC did not consider the Resource’s Start-Up Offer in the original commitment decision, except for commitments made as described under Sections 5.2.2(3), 6.1.2(3) and 6.1.2(4) of this Attachment AE, the Resource’s Start-Up Offer shall equal zero.

(iii) A Resource’s RTBM Start-Up costs are not eligible for recovery in the following RUC make whole payment eligibility periods:

1. Any RUC make whole payment eligibility period for which a Resource is a Synchronized Resource prior to this commitment period at a time one (1) hour prior to that Resource’s RUC Commit Time in addition to the Resource’s Sync-To-Min Time unless the RUC make whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the one (1) hour in addition to the Resource’s Sync-To-Min Time; or

2. For any RUC make whole payment eligibility period for which a Staggered Start Resource is a Synchronized Resource prior to this commitment period at a time two (2) hours prior to that Resource’s RUC Commit Time in addition to the Resource’s Sync-To-Min Time unless the RUC market whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the two (2) hours in addition to the Resource’s Sync-To-Min Time; or

3. For any RUC make whole payment eligibility period for which the commitment is made in conjunction with RTBM offline Uncertainty Reserve clearing.

(iv) When there is a cost transferred from the Day-Ahead Market make whole payment as described in Section 8.5.9(3)(b)(iii) of this Attachment AE, the commitment level cost in the RUC make
whole payment is increased by the amount allocated to the RUC make whole payment as described in Section 8.5.9(3)(b)(iii) of this Attachment AE.

(v) In any RUC make whole payment eligibility period for which the RUC SCUC considered the Resource’s Transition State Offer in the original commitment decision, or the RTBM Transition State Offer is associated with a manual commitment as described under Sections 5.2.2(3), 6.1.2(3) and 6.1.2(4) of this Attachment AE, the Transition State Offer cost is eligible for recovery when the following conditions are met:

1. In at least one Dispatch Interval during the scheduled configuration period, the Resource is in the target “from” configuration and the Resource must be a Synchronized Resource; and
2. In at least one Dispatch Interval during the scheduled configuration period, the Resource is in the target “to” configuration and the Resource must be a Synchronized Resource.

(vi) If the Transmission Provider cancels a transition between configurations prior to the scheduled transition associated with a RUC make whole payment eligibility period, the Asset Owner will be eligible to recover a time-based pro-rata share of the Resource’s RTBM Transition State Offer through the RUC make whole payment unless precluded by Section 8.6.5(3)(e)(i) of this Attachment AE. Asset Owners may request additional compensation through submittal of actual cost documentation to the Transmission Provider. The Transmission Provider will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.
(vii) When a Resource loses eligibility to recover a Start-Up Offer cost for the reason described in Section 8.6.5(3)(e)(iii)(1) of this Attachment AE, or loses eligibility to recover Transition State Offer costs for the reason described in Section 8.6.5(3)(v) of this Attachment AE, to prevent overstating avoided costs, the commitment level cost is adjusted by the lesser of: (1) its Start-Up Offer cost and Transition State Offer cost associated with commitments that have a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a) of this Attachment AE; or (2) the ineligible RTBM Start-Up Offer cost plus the ineligible Transition State Offer costs.

(viii) For each RUC make whole payment eligibility period within an Operating Day, a Resource’s eligible Start-Up cost is divided by the lesser of (1) the hours of RUC commitment within the Resource’s applicable Minimum Run Time multiplied by twelve (12), rounded down to the nearest whole interval, or (2) twenty-four (24) hours multiplied by twelve (12), to achieve a Dispatch Interval proration for the purpose of allocating Start-Up costs across adjacent Day-Ahead Market or RUC make whole payment eligibility periods.

(1) If the number of participating Dispatch Interval meets or exceeds the duration of the divisor as described in (viii) above, the full cost of the Start-Up Offer is included in the commitment level cost for the RUC make whole payment eligibility period.

(2) If the number of participating Dispatch Intervals is less than the duration of the divisor as described in (viii) above, the proration is multiplied by the number of participating Dispatch Intervals to achieve a single Start-Up Offer amount to be included in the commitment level cost for that RUC make whole payment eligibility period. Any
remaining eligible RUC Start-Up cost will be included in the commitment level cost for the following and adjacent Day-Ahead Market make whole payment eligibility period as described in Section 8.6.5(3)(f) of this Attachment AE or the following and adjacent RUC make whole payment eligibility period in the next Operating Day.

(f) If the Resource has been committed in the Day-Ahead Market in a period adjacent to and following a RUC make whole payment eligibility period to the extent that the full amount of the eligible RTBM Start-Up cost is not accounted for in the RUC make whole payment eligibility period, any remaining eligible RTBM Start-Up cost is carried forward for recovery in the Day-Ahead make whole payment eligibility period.

(g) If a Resource has operated outside of its Operating Tolerance in any Dispatch Interval, any cost associated with energy injection or withdrawal above the Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Section 8.6.5(4)(d) of this Attachment AE.

(h) If a Resource becomes non-dispatchable in any Dispatch Interval, any cost associated with energy injection or withdrawal above the Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Section 8.6.5(4)(d) of this Attachment AE.

(i) (1) If a Resource’s minimum operating limit is increased above the Resource’s minimum operating limit that was used to make the commitment decision, the increase is greater than the Resource’s Operating Tolerance and the Resource remains dispatchable in any Dispatch Interval, any cost associated with energy injection or withdrawal above the Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Section 8.6.5(4)(d) of this Attachment AE, or (2) if a Resource is committed and subsequent to that commitment, the Resource’s originally
submitted limits are modified such that the Resource’s availability switches from injection to withdrawal, any cost associated with energy withdrawal below the Resource’s economic operating point resulting from changing its availability from injection to withdrawal is not eligible for recovery for the Dispatch Interval for which such cost is calculated. If a Resource is committed and subsequent to that commitment, the Resource’s originally submitted limits are modified such that the Resource’s availability switches from withdrawal to injection, any cost associated with energy injection above the Resource’s economic operating point resulting from changing its availability from withdrawal to injection is not eligible for recovery for the Dispatch Interval for which such cost is calculated.

(j) If a Resource’s self-commitment period is less than the Resource’s Minimum Run Time, the Transmission Provider will relax the Resource’s Minimum Run Time to equal the self-commit period.

(k) If a Resource is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE in the RTBM, the Resource will be eligible to recover applicable recurring costs as defined in Section 8.6.5(4)(b) of this Attachment AE for that period in the RUC make whole payment eligibility period.

(l) For an MCR, additional costs of revenues incurred when the Resource has cleared Operating Reserve in the Day-Ahead Market and must buy back that position in Real-Time will be considered as an adjustment when determining a RUC make whole payment. These costs or revenues must be incurred during time periods in which the Resource is ineligible to clear Operating Reserve products due to transitioning between configurations in Real-Time where at least one configuration is the result of a RUC commitment, and the transition is not forced by the Resource Offer. The Market Participant may also be eligible to recover Operating Resource product buy back costs or revenue incurred during a Real-Time transition if the Resource is transitioned by a local transmission operator to address a
Local Emergency Condition (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE), then such Resources are not eligible to recover any costs or revenues associated with the transition as part of a RUC make whole payment. In such cases, the adjustment is equal to the sum of the cleared Day-Ahead Market Operating Reserve revenue as calculated from the Day-Ahead Operating Reserve MCP and the cleared incremental RTBM Operating Reserve revenue as calculated from the RTBM Operating Reserve MCPs. For Contingency Reserve, Ramp Capability Up, and Ramp Capability Down, and Uncertainty Reserve the adjustment is limited to the time period defined as the transition State Time submitted in the Resource Offer. For Regulation-Up and/or Regulation-Down, the adjustment is limited to all Dispatch Intervals within the transition hour.

(4) The payment to each Asset Owner for each eligible Settlement Location for a given RUC make whole payment eligibility period is calculated as follows:

RUC Make Whole Payment Amount =

Maximum of [Either Zero or (RUC Make Whole Payment Commitment Cost Amount + RUC Make Whole Payment Cost Amount in the RUC Make Whole Payment Eligibility Period + RUC Make Whole Payment Revenue Amount in the RUC Make Whole Payment Eligibility Period – Uninstructed Resource Deviation Cost Disallowance – Non-Dispatchable Cost Disallowance – Minimum Limit Cost Disallowance + Real-Time Combined Cycle Operating Reserve Adjustment Amounts)]

(a) An Asset Owner’s Real-Time Make Whole Payment Commitment Cost Amount for each eligible Resource in the RUC make whole payment eligibility period is equal to:

(i) Start-Up Offer used to make the commitment decision which was committed by the Transmission Provider or by a local transmission operator to address a Local Emergency Condition (unless such commitment instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE); plus
(ii) The Transition State Offer used to make the transition decision for an MCR that cleared in the Day-Ahead Market or committed by the RUC process that were transitioned by the Transmission Provider into a different configuration in Real-Time or transitioned by a local transmission operator to address a Local Emergency Condition (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE); plus

(iii) Real-Time Cancelled Transition Amount as described in Section 8.6.5(3)(e)(vi) of this Attachment AE; plus

(iv) Amount of shared Start-Up costs between Day-Ahead Market and RUC make whole payment eligibility periods as described in Section 8.5.9(3)(b)(iii) of this Attachment AE; plus

(v) Amount of costs where the Resource loses eligibility to recover as describe in Section 8.6.5(3)(e)(vii) of this Attachment AE, minus

(vi) The sum of all Start-Up Offer cost and Transition State Offer cost associated with the schedule created by combining (1) all Day-Ahead Market commitments with a Day-Ahead Market Resource Offer commitment status as defined under Section 4.1(10)(a), (b) or (c) of this Attachment AE contained within a RUC make whole payment eligibility period and (2) all RUC commitments that are associated with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a) of this Attachment AE within a RUC make whole payment eligibility period.

(b) An Asset Owner’s RUC Make Whole Payment Cost Amount for each eligible Resource is equal to the sum for all Dispatch Intervals in the RUC commitment of:

(i) No-Load Offer used to make the RUC commitment decision, less any Day-Ahead Market No-Load from an MCR resulting from a different Day-Ahead Market committed configuration where the No-Load Offer shall be included as zero for Dispatch Intervals
constituting the larger of the Uncertainty Reserve response time or Minimum Run Time of a RUC commitment made in conjunction with offline Uncertainty Reserve clearing;

(ii) Energy cost at minimum injection or withdrawal as calculated from the Energy Offer Curve used to make the commitment decision where this Energy cost at minimum shall be included as zero for Dispatch Intervals constituting the larger of the Uncertainty Reserve response time or Minimum Run Time of a RUC commitment made in conjunction with offline Uncertainty Reserve clearing;

(iii) Energy cost above minimum injection or withdrawal as calculated from the Energy Offer Curve that applied to the current Dispatch Interval;

(iv) For MCRs, the Energy cost shall be calculated from the Energy Offer Curve used in the Day-Ahead Market from zero to the lesser of (1) Day-Ahead Market cleared Energy or (2) the submitted meter in Real-Time, multiplied by (-1);

(v) For Resources (other than MCRs cleared in the Day-Ahead Market that were committed into a different configuration in Real-Time), Operating Reserve cost, including the impact from product substitution as described under Section 3.1.7 of this Attachment AE, associated with cleared Real-Time Operating Reserve. Excess Regulation-Up Mileage and Excess Regulation-Down Mileage as calculated from the Operating Reserve Offers, except when those costs are associated with self-scheduled Operating Reserve which is greater than or equal to the amount of Operating Reserve cleared, in which case all three of these costs shall be set equal to zero;

(vi) For an MCR that was cleared in the Day-Ahead Market and was committed into a different configuration in Real-Time and is not transitioning into that configuration, the Operating Reserve cost,
including the impact from product substitution as described under Section 3.1.7 of this Attachment AE, associated with cleared Real-Time Operating Reserve minus Day-Ahead Operating Reserve cost, including the impact from product substitution as described under Section 3.1.7 of this Attachment AE, associated with the lesser of (1) cleared Real-Time Operating Reserve or (2) cleared Day-Ahead Operating Reserve, except when self-scheduled Operating Reserve is less than or equal to the amount of Real-Time Operating Reserve cleared then the Operating Reserve cost shall be set equal to zero;

(vii) Real-Time Potential Regulation-Up Unused Mileage Make Whole Payment as calculated under Section 8.6.19(2)(b) of this Attachment AE; and

(viii) Real-Time Potential Regulation-Down Unused Mileage Make Whole Payment as calculated under Section 8.6.20(2)(b) of this Attachment AE.

(c) An Asset Owner’s RUC Make Whole Payment Revenue Amount for each eligible Resource that is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE is equal to the sum of the following for all Dispatch Intervals in the RUC commitment:

(i) Dispatch Interval revenue associated with Energy calculated by multiplying actual Dispatch Interval Energy injection or withdrawal by Real-Time LMP, except for MCRs that cleared in the Day-Ahead Market and were transitioned into a different configuration in Real-Time, in which case such revenue is calculated by multiplying Real-Time LMP by the incremental increase of the actual Dispatch Interval Energy injection or withdrawal above the Day-Ahead cleared Energy;

(ii) the sum of the revenues calculated under Sections 8.6.3 and 8.6.4 of this Attachment AE for that eligible Resource;
(iii) Energy revenue associated with payments made under Section 8.6.6 of this Attachment AE;
(iv) amounts associated with settlement made under Section 8.6.15 of this Attachment AE;
(v) Real-Time Unused Regulation-Up Mileage Make Whole Payment as calculated under Section 8.6.19(2) of this Attachment AE;
(vi) Real-Time Unused Regulation-Down Mileage Make Whole Payment as calculated under Section 8.6.20(2) of this Attachment AE;
(vii) Real-Time Regulation-Up Service Revenue as calculated under Section 8.6.19(2)(a)(i) of this Attachment AE;
(viii) Real-Time Regulation-Down Service Revenue as calculated under Section 8.6.20(2)(a)(i) of this Attachment AE;
(ix) Excess Regulation-Up Mileage Dispatch Interval Amount as calculated under Section 8.6.2(1)(a)(v) of this Attachment AE, multiplied by (-1);
(x) Excess Regulation-Down Mileage Dispatch Interval Amount as calculated under Section 8.6.2(2)(a)(v) of this Attachment AE, multiplied by (-1); and
(xi) the sum of the revenues calculated under Section 8.6.26 of this Attachment AE; and
(xii) Real-Time Uncertainty Reserve revenue as calculated under Section 8.6.29 of this Attachment AE.

(d) An Asset Owner’s Uninstructed Resource Deviation Cost Disallowance, Non-Dispatchable Cost Disallowance, or Minimum Limit Cost Disallowance is equal to the positive difference between the Resource’s Energy cost at actual injection or withdrawal as calculated from the Resource’s current Dispatch Interval Energy Offer Curve and the Resource’s Energy cost at the Resource’s economic operating point as calculated from the Resource’s current Dispatch Interval Energy Offer Curve.
(e) A Resource’s economic operating point is the MW injection or withdrawal where the cost on the Resource’s current Dispatch Interval Energy Offer Curve first exceeds the Real-Time DLMP for that Resource.

(f) For MCRs that have been transitioned into a different configuration in Real-Time and are transitioning into that configuration, the Real-Time Combined Cycle Operating Reserve Adjustment Amount shall be equal to the sum of the cleared Day-Ahead Market Operating Reserve revenue as calculated from the Day-Ahead Operating Reserve MCP and the cleared incremental RTBM Operating Reserve revenue as calculated from the RTBM Operating Reserve MCPs.
8.6.29 Real-Time Uncertainty Reserve Amount

(1) An RTBM payment or charge for deviations between cleared RTBM Uncertainty Reserve and cleared Day-Ahead Market Uncertainty Reserve will be calculated at each Settlement Location by Asset Owner for each Dispatch Interval and hour as follows:

(a) Real-Time Uncertainty Reserve Dispatch Interval Amount =

\[
[(\text{Real-Time MCP}) \times ((\text{Real-Time Cleared Uncertainty Reserve Dispatch Interval Quantity}) - \text{(Day-Ahead Uncertainty Reserve Hourly Quantity)}) / 12] \times (-1)
\]

(i) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Uncertainty Reserve associated with the Reserve Zone in which the applicable Resource is located.

(ii) Asset Owner Real-Time Cleared Uncertainty Reserve Dispatch Interval Quantity is the MW quantity associated with cleared Uncertainty Reserve as described under Section 6.2.3 of this Attachment AE.

(iii) Asset Owner Day-Ahead Cleared Uncertainty Reserve Hourly Quantity is the MW quantity associated with cleared Day-Ahead Market Uncertainty Reserve as described under Section 5.1.3 of this Attachment AE.

(b) Real-Time Uncertainty Reserve Hourly Amount =

\[\text{Sum of Real-Time Uncertainty Reserve Dispatch Interval Amount over all Dispatch Intervals in the Hour.}\]

(2) If a Resource is mitigated for the Uncertainty Reserve product, is subsequently committed in conjunction with RTBM offline Uncertainty Reserve clearing, and Uncertainty Reserve mitigation caused reduced Uncertainty Reserve payments which did not cover the Resource costs excluded from the make whole payment due to the Uncertainty Reserve related commitment then the Resource may file a dispute for such mitigation caused shortfall.
8.6.30 Real-Time Uncertainty Reserve Distribution Amount

(1) An RTBM payment or charge will be calculated by Asset Owner at each Settlement Location for each hour for the purposes of funding the payments made under Section 8.6.29 of this Attachment AE as follows:

Real-Time Uncertainty Reserve Distribution Amount = 

[(Real-Time Uncertainty Reserve Amount) * (Real-Time Load Ratio Share)] * (-1)

(a) The Real-Time Uncertainty Reserve Amount shall be equal to the sum of the all payments made under Section 8.6.29 of this Attachment AE for Uncertainty Reserve procurement for the hour.

(b) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.
8.6.31 Real-Time Uncertainty Reserve Non-Performance Amount

An RTBM payment or charge will be calculated at each Resource Settlement Location for each Asset Owner for each Dispatch Interval when a Resource with cleared RTBM Uncertainty Reserve does not operate in a responsive manner.

When a Resource with cleared online Uncertainty Reserve in the current Dispatch Interval is not dispatchable in one or more of the subsequent Dispatch Intervals within the Uncertainty Reserve response time following the current Dispatch Interval, except by Transmission Provider instruction, such as an OOME or decommitment, which prevents the Resource from being as seen as dispatchable, the amount will be determined as follows:

Real-Time Uncertainty Reserve Non-Performance Amount =


(1) Real-Time Uncertainty Non-Performance Ratio portion of non-dispatchable intervals in the subsequent Dispatch Intervals within the Uncertainty Reserve response time.

(2) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Uncertainty Reserve associated with the Reserve Zone in which the applicable Resource is located.

(3) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Uncertainty Reserve associated with the Reserve Zone in which the applicable Resource is located.

(4) An Asset Owner’s Day-Ahead Cleared Uncertainty Reserve Hourly Quantity is the MW quantity associated with cleared Uncertainty Reserve as described under Section 5.1.3 of this Attachment AE.

(5) An Asset Owner’s Real-Time Cleared Uncertainty Reserve Dispatch Interval Quantity is the MW quantity associated with cleared Uncertainty Reserve as described under Section 6.2.3 of this Attachment AE.
When a Resource with cleared offline Uncertainty Reserve fails to start when called on in association with Uncertainty Reserve, the amount will be determined as follows in each interval:

Real-Time Uncertainty Reserve Non-Performance Amount =

If the Resource failed to start and was ineligible to recover startup cost associated within an offline uncertainty commitment, then the startup cost distributed equally over the larger of the Minimum Run Time or the Uncertainty Reserve response time during a single Operating Day of the eligibility period + [if the Resource was offline in a committed interval in which it was not eligible to recover no-load and Energy at minimum costs due to being associated with an offline uncertainty commitment, the as-committed No-Load Offer + as-committed Energy Offer at minimum cost)/12].
8.6.32 Real-Time Uncertainty Reserve Non-Performance Distribution Amount

An RTBM payment or charge will be calculated for each Asset Owner at each Settlement Location for each hour in order to distribute the funds collected under Section 8.6.31 of this Attachment AE. The Asset Owner amount is calculated as follows:

Real-Time Uncertainty Reserve Non-Performance Distribution Amount =

\[(\text{Real-Time Uncertainty Reserve Non-Performance Amount}) \times (\text{Real-Time Load Ratio Share})\] \times (-1)

(1) The Real-Time Uncertainty Reserve Non-Performance Amount shall be equal to the sum of all charges made under Section 8.6.31 of this Attachment AE for each hour.

(2) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.

This section sets forth the market power mitigation measures that are applied in the Day-Ahead Market, Reliability Unit Commitment processes and the Real-Time Balancing Energy Markets, collectively referred to as the Energy and Operating Reserve Markets.

3.1 Local Market Power Test

A Resource satisfying at least one of the following conditions is determined to have local market power:

1. The Resource is located in a Frequently Constrained Area, as described in Section 3.1.1, and one or more of the transmission constraints that define the Frequently Constrained Area is binding or the Reserve Zone that defines the area is binding;

2. The Resource is not in a Frequently Constrained Area and
   a. has a Resource-to-Load-Distribution factor less than or equal to negative five percent (-5%) relative to a binding transmission constraint; or
   b. is located in a binding Reserve Zone;

3. The Resource is committed, or the Multi-Configuration Resource (“MCR”) is transitioned, as defined in Attachment AE, to address a Local Reliability Issue.

3.1.1 Frequently Constrained Areas

A Frequently Constrained Area is an electrical area identified by the Market Monitor that is defined by one or more binding transmission constraints or binding Reserve Zone constraints that are expected to be binding for at least five-hundred (500) hours during a given twelve (12)-month period and within which one (1) or more suppliers are pivotal. All Frequently Constrained Area designations along with supporting analysis shall be posted on the Transmission Provider’s website.

3.1.1.1 Pivotal Supplier Test

A supplier is pivotal when the energy output or provision of operating reserves by any or some of its Resources jointly must be
increased or decreased to resolve the binding transmission constraint or binding Reserve Zone constraint during some or all hours. This will be determined utilizing transmission load flow cases or RTBM market cases reflecting a variety of market conditions.

These load flow or market cases will be used to estimate: (i) the generation shift factors for all relevant Resources and relevant resources outside the SPP Balancing Authority Area relative to each potentially constrained flowgate; (ii) the capability of all Resources to meet the requirements of each binding Reserve Zone constraint; (iii) the base loadings of Resources; (iv) the base allocation of Operating Reserves on Resources; and (v) the base flows on each flowgate. A supplier is pivotal when a binding transmission constraint or a binding Reserve Zone constraint cannot be relieved by changing the base loadings for other suppliers’ Resources.

3.1.1.2 Initial Designation of Frequently Constrained Areas

The Market Monitor will define and recommend the Frequently Constrained Areas to the SPP Board of Directors prior to the start of the Integrated Marketplace.

3.1.1.3 Changes to Frequently Constrained Area Designation

The Market Monitor shall reevaluate the Frequently Constrained Areas at least annually. A reevaluation may be performed more frequently if the Market Monitor believes that conditions have changed with respect to the binding transmission constraints or binding Reserve Zone constraints that define a Frequently Constrained Area, or if congestion on constraints that are not designated as a Frequently Constrained Area warrant a new analysis. The Transmission Provider may also propose an area be designated or undesignated as a Frequently Constrained Area to the Market Monitor. The Market Monitor will post the updated
Frequently Constrained Area information along with the associated analysis on the Transmission Provider’s website at least 14 calendar days prior to the Frequently Constrained Area updates becoming effective and will notify Market Participants of the posting. Market Participants may contact the MMU within the 14 day posting period if there are concerns with the Market Monitor’s proposed updates. The Market Monitor will consider and respond to Market Participant concerns and will make updates if needed. The Market Monitor will notify Market Participant when updates become effective.

3.2 Mitigation Measures for Energy Offer Curves

Mitigated Energy Offer Curves shall be submitted on a daily basis by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. For MCRs, for which a single configuration allows physical units to be swapped (e.g., Combustion Turbine 2 for Combustion Turbine 1), the costs used in the mitigated offer development for that configuration shall be those of the least cost physical unit that is available and can be swapped in such configuration. The mitigated Energy Offer Curve may be updated up to the close of the Day-Ahead Market as defined in Section 5.1 of Attachment AE of this Tariff for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Energy Offer Curve may be updated until the Day-Ahead RUC begins. For Resources committed by the Day-Ahead Market, the mitigated Energy Offer Curve submitted as of the close of the Day-Ahead Market will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day unless an exception is allowed in Section 3.2(J) of this Attachment AF; for all other Resources the mitigated Energy Offer Curve submitted at the time the Day-Ahead RUC begins will apply to the Day-Ahead RUC on the day before the Operating Day, and the Intra-Day RUC processes and the RTBM on the Operating Day. For the pricing SCED, the composite Energy Offer Curve and mitigated composite Energy Offer Curve will be calculated and used by the Transmission Provider for FSRs in the
Day-Ahead Market and RTBM as described in Section 3.3.1 of Attachment AE of this Tariff.

A. For a Resource with an Energy Offer Curve greater than or equal to $25/MWh that was not committed to address a Local Reliability Issue, the conduct thresholds are as follows:

   (1) For a Resource located in a Frequently Constrained Area, the conduct threshold is a 17.5% increase above the mitigated Energy Offer Curve;
   
   (2) For a Resource not located in a Frequently Constrained Area, the conduct threshold is a 25% increase above the mitigated Energy Offer Curve.

B. For a Resource with an Energy Offer Curve greater than or equal to $25/MWh that was not committed to address a Local Reliability Issue, the Transmission Provider shall apply mitigation measures by replacing the Energy Offer Curve with the mitigated Energy Offer Curve if:

   (1) The Resource’s Energy Offer Curve exceeds the mitigated Energy Offer Curve by the applicable conduct threshold; and
   
   (2) The Resource has local market power as determined in Sections 3.1(1) or 3.1(2); and
   
   (3) The Resource either:
       
       (a) Fails the Market Impact Test as described in Section 3.7, or
       
       (b) Is manually committed by the Transmission Provider or by a local transmission operator.

A Resource with an Energy Offer Curve below $25/MWh shall not be subject to mitigation measures on its Energy Offer Curve for economic withholding.

C. For a Resource with an Energy Offer Curve greater than or equal to $25/MWh that has local market power as determined in Section 3.1(3), the Transmission Provider shall apply mitigation measures by placing a cap on the Energy Offer Curve of 10% above the mitigated Energy Offer Curve. A Resource with an Energy Offer Curve below $25/MWh shall
D. The mitigated energy offer shall be the Resource’s short-run marginal cost of producing energy as determined by the unit’s heat rate or similar production efficiency ratio; fuel costs and the costs related to fuel usage, such as transportation and emissions costs (“total fuel related costs”); and Energy Offer Curve (“EOC”) variable operations and maintenance costs (“VOM”) as detailed in the Market Protocols and the charges incurred from Schedules 1-A3 and 1-A4 of this Tariff.

E. For Resources that are not ESRs, opportunity cost shall be an estimate of the Energy and Operating Reserve Markets revenues net of short run marginal costs for the marginal forgone run time during the timeframe when the Resource experiences the run-time restrictions as detailed in the Market Protocols. The run-time restrictions shall be updated as specified in the Market Protocols, with more frequent updating to occur the fewer hours that remain available, consistent with the Market Protocols. The Market Participant may include in the calculation of its mitigated Energy Offer Curve an amount reflecting the resource-specific opportunity costs expected to be incurred under the following circumstances:

1. Externally imposed environmental run-hour restrictions; or
2. Physical equipment limitations on the number of starts or run-hours, as verified by the Market Monitoring Unit and determined by reference to the manufacturer’s recommendation or bulletin, or a documented restriction imposed by the applicable insurance carrier; or
3. Fuel Supply Limitations.

Resource specific opportunity costs are calculated by forecasting Locational Marginal Prices based on futures contract prices for natural gas and the historical relationship between the SPP system marginal Energy component of LMP and the price of natural gas, as determined by the SPP Market Monitoring Unit. The formulas and instructions in the price
forecast model shall be determined by the SPP Market Monitoring Unit and published in the Market Protocols as part of the Mitigated Offer Development Guidelines, updated, as needed, by the SPP Market Monitoring Unit. Such forecasts of LMPs shall take into account historical variability, and basis differentials affecting the Settlement Location at which the Resource is located for the three-year period immediately preceding the period of time in which the Resource is bound by the referenced restrictions, and shall subtract therefrom the forecasted costs to generate energy at the Settlement Location at which the Resource is located, as specified in more detail in Appendix G of the Market Protocols. If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative, the resulting opportunity cost shall be zero. The Market Monitoring Unit will verify all Market Participants’ opportunity cost calculations for consistency and accuracy. When the Market Monitoring Unit determines that the market price for any period was not competitive, it will adjust the LMP forecasting process used in the opportunity cost calculations to ensure that forecasted LMPs do not reflect non-competitive market conditions.

The following formula shall apply to all mitigated Energy Offer Curves unless specified otherwise in this Section 3.2(E) of this Attachment AF:

\[
\text{Mitigated Energy Offer ($/MWh) = HeatRate (mmBtu/MWh) } \times \text{ Performance Factor } \times \text{ Total Fuel Related Costs ($/mmBtu) + EOC VOM ($/MWh) + Opportunity Costs ($/MWh) + Schedule 1-A3 Charge ($/MWh) + Schedule 1-A4 Charge ($/MWh)}
\]

F. The Market Participant shall submit heat rate curves, descriptions of how spot fuel prices and/or contract prices are used to calculate fuel costs, variable fuel transportation and handling costs, emissions costs, and VOM to the Market Monitoring Unit. All cost data and cost calculation descriptions are subject to the review and approval of the SPP Market Monitoring Unit to ensure reasonableness and consistency across Market Participants. The information will be sufficient for replication of the
mitigated Energy Offer Curve and shall include, among other data, the following information:

(1) For fuel costs, Market Participants shall provide the Market Monitoring Unit with an explanation of the Market Participants’ fuel cost policy, indicating whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or referenced spot market prices. Any included fuel transportation and handling costs must be short-run marginal costs only, exclusive of fixed costs.

(2) For emissions costs, Market Participants shall report the emissions rate of each of their units and indicate the applicable emissions allowance cost.

(3) For VOM costs, Market Participants shall submit VOM costs, calculated in adherence with the Appendix G of the Market Protocols, reflecting short-run marginal costs, exclusive of fixed costs.

Further details associated with the development, validation, and updating of these costs are included in Appendix G of the Market Protocols.

G. For Demand Response Resources utilizing Behind-The-Meter Generation, the mitigated Energy Offer Curve shall be developed in the same manner as any other generating Resource as described above. For Demand Response Resources utilizing load reduction, the mitigated Energy Offer Curve shall reflect the quantifiable opportunity costs associated with the reduction, net of related offsetting increases in usage.

H. For Dispatchable Variable Energy Resources, the mitigated Energy Offer Curve may include, but shall not exceed, any quantifiable costs that vary by MWh output, including short-run incremental VOM. Mitigation will not apply to Non-Dispatchable Variable Energy Resources in the Real-Time Balancing Market; monitoring of Energy Offers for Non-Dispatchable Variable Energy Resources will occur.
I. For an ESR, the mitigated Energy Offer Curve may include, but shall not exceed, (i) charging cost and (ii) opportunity cost, both adjusted for round-trip efficiency. Charging cost is the cost at which the ESR charged, and opportunity cost is the average profit in the next hour forgone by charging or discharging in the current hour. The sum of the charging cost and opportunity cost is the average LMP that is expected for the next Operating Hour. This expected average LMP for the next Operating Hour is the unweighted average of the LMPs for the most recent 45 days comparing like Operating Hours. The mitigated Energy Offer Curve for MSRs shall have at least two breakpoints: one for charging and another for discharging. More breakpoints may be added to the extent that other costs vary.

The following formula shall apply to mitigated Energy Offer Curves for ESRs:

\[
\text{Charging Mitigated Energy Offer (}$/\text{MWh}$) = \text{Performance Factor} \times \text{Average LMP Expected for the Next Hour ($}/\text{mmBtu}$) \times \text{Round-Trip Efficiency - EOC VOM ($}/\text{MWh}$)
\]

\[
\text{Discharging Mitigated Energy Offer (}$/\text{MWh}$) = \text{Performance Factor} \times \text{Average LMP Expected for the Next Hour ($}/\text{mmBtu}$) / \text{Round-Trip Efficiency + EOC VOM ($}/\text{MWh}$)
\]

J. Intra-day changes to the mitigated Energy Offer Curve are allowed under the following conditions:

(1) In the event that the Transmission Provider requests that a Resource remain online past their commitment period by the Day-Ahead Market or a RUC process, the Market Participant may submit an updated mitigated Energy Offer Curve that reflects the procurement of higher cost fuel;

(2) A Resource must switch fuels due to unforeseen operating conditions; or

(3) The Resource is an ESR.
Intra-day changes to the mitigated Energy Offer Curve must follow the mitigated offer development guidelines in Appendix G of the Market Protocols. Any such changes will be validated by the Market Monitor.

K. A Market Participant that has a Resource with short-run marginal costs greater than the Safety-net Energy Offer Cap specified in Section 4.1.1 of Attachment AE of this Tariff may submit an Energy Offer Curve using the same guidelines for development of the Resource’s Mitigated Energy Offer Curve established in Appendix G of the Market Protocols. The Energy Offer Curve above $1,000/MWh must be equal to the Mitigated Energy Offer Curve and may include an adder with a maximum of $100/MWh due to the uncertainty of expected costs. For purposes of LMP calculation, the Energy Offer Curve will be limited to a maximum of $2,000/MWh and will have to be verified by the Market Monitor prior to the start of the applicable market clearing process. If the Energy Offer Curve cannot be verified prior to the start of the applicable market clearing process, then the Resource may be eligible to receive make-whole payments for its actual costs after verification by the Market Monitor. The default value is $1,000/MWh for any offer above $1,000/MWh until the offer can be verified. If the verified Energy Offer Curve is greater than $2,000/MWh, the Energy Offer Curve will be capped at $2,000/MWh in the applicable market clearing process, and the Resource may be eligible for make-whole payments for actual costs exceeding $2,000/MWh. Market Participants must submit evidence of actual costs to the Market Monitor. The Market Monitor shall verify the actual costs for use in make-whole payments. In order to include the costs in the make-whole payments of the final Settlement Statement, the submission must occur within 35 calendar days after the Operating Day and the verification must be complete no later than noon on the business day prior to 45 calendar days after the Operating Day.

L. In all cases under this Section 3.2, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the
confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

3.3 Mitigation Measures for Start-Up Offers and No-Load Offers

A mitigated Start-Up Offer and a mitigated No-Load Offer shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. The mitigated Start-Up and No-Load Offers may be updated up to the close of the Day-Ahead Market for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the Start-Up and No-Load Offers may be updated until the Day-Ahead RUC begins. The mitigated Start-Up and No-Load Offers submitted at the time the Day-Ahead RUC begins will apply to the Day-Ahead RUC on the day before the Operating Day and the Intra-Day RUC on the Operating Day unless an exception is allowed in Section 3.3(G) of this Attachment AF.

A. For a Resource that was not committed to address a Local Reliability Issue, the Start-Up and No-Load Offer conduct threshold is a 25% increase above the mitigated Start-Up or mitigated No-Load Offer, as applicable.

B. For a Resource that was not committed to address a Local Reliability Issue, the Transmission Provider shall apply mitigation measures by replacing the Start-Up or No-Load Offer with the applicable mitigated Start-Up or No-Load Offer if:

1. The Resource’s Start-Up or No-Load Offer exceeds the mitigated Start-Up or mitigated No-Load Offer, as applicable, by the applicable conduct threshold; and

2. The Resource has local market power as determined in Sections 3.1(1) or 3.1(2); and

3. The Resource either:
   (a) Fails the Market Impact Test as described in Section 3.7, or
   (b) Is manually committed by the Transmission Provider or by a local transmission operator.
C. For a Resource that has local market power as determined in Section 3.1(3), the Transmission Provider shall apply mitigation measures by placing a cap on the Start-Up Offer or No-Load Offer of 10% above the mitigated Start-Up Offer or No-Load Offer, as applicable.

D. The mitigated Start-Up Offer shall represent the cost per start as determined from start fuel usage and the costs related to that fuel usage, Performance Factor, cost of electricity for station use to start ("Station Service"), start-up VOM cost, start major maintenance cost, and start additional labor costs, if required above normal station staffing levels. Further guidelines for the mitigated Start-Up Offer are documented in Appendix G of the Market Protocols.

The mitigated Start-Up Offer for Demand Response resources shall be the cost to shut down or curtail load for a given period, which varies with the number of deployments rather than the amount of response, and/or the start cost of Behind-The-Meter Generation utilizing the mitigated Start-Up Offer calculation applicable to other generation Resources as defined above.

The mitigated Start-Up Offer for Variable Energy Resources shall be zero.

E. The mitigated No-Load Offer shall be the hourly fixed cost, represented in $/hr, required to operate the Resource at zero electricity output to the grid. The mitigated No-Load Offer can be calculated using either (1) the no-load fuel approach that includes no-load fuel (mmBtu/hour), Performance Factor, no-load VOM cost ($/mmBtu), total fuel related cost ($/mmBtu), and no-load major maintenance cost ($/hr); or (2) calculated using the no-load cost approach that includes heat input at Minimum Economic Capacity Operating Limit (mmBtu), Performance Factor, total fuel related cost ($/mmBtu), no-load VOM cost ($/mmBtu), incremental cost up to Minimum Economic Capacity Operating Limit ($/MWh), Minimum Economic Capacity Operating Limit (MW), and no-load major maintenance cost ($/hr). Further guidelines for the mitigated No-Load Offer are documented in Appendix G of the Market Protocols.
The mitigated No-Load Offer for Demand Response Resources utilizing Behind-The-Meter Generation shall adhere to the same definition above as a generating Resource. For Demand Response Resources utilizing load reduction, the mitigated No-Load Offer shall not exceed the quantifiable ongoing hourly costs associated with load reduction.

The mitigated No-Load Offer for Variable Energy Resources shall be zero.

F. The Market Participant shall submit all inputs used in calculating mitigated Start-Up and mitigated No-Load Offers to permit the Market Monitor to verify submitted offers. Required information includes: heat rate curves, descriptions of how spot fuel prices and/or contract prices are used to calculate fuel costs, variable fuel transportation and handling costs, emissions costs, and VOM cost. All cost data and cost calculation descriptions are subject to the review and approval of the SPP Market Monitoring Unit to ensure reasonableness and consistency across Market Participants. Information to be provided by the Market Participant shall include the following:

(1) For fuel costs, Market Participants shall provide the Market Monitoring Unit with an explanation of the Market Participants’ fuel cost policy, indicating whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or referenced spot market prices. Any included fuel transportation and handling costs must be short-run marginal costs only, exclusive of fixed costs.

(2) For emissions costs, Market Participants shall report the emissions rate of each of their units and indicate the applicable emissions allowance cost.

(3) For VOM costs, Market Participants shall submit VOM costs reflecting short-run marginal costs, exclusive of fixed costs.

(4) For start and no-load major maintenance cost, Market Participants may include these costs as a component of the mitigated Start-Up
Offer and the mitigated No-Load Offer. Such cost must be based solely on resource-specific information derived from actual variable maintenance costs, when available, or estimated variable maintenance costs. The maintenance period for start major Maintenance cost must be tied to the number of starts, and the maintenance period for no-load major maintenance cost must be tied to the number of Resource run hours.

Further details associated with the development, validation and updating of these costs are included in Appendix G of the Market Protocols.

G. Intra-day changes to the mitigated Start-Up and mitigated No-Load Offers are allowed under the following conditions:

1. In the event that the Transmission Provider requests that a Resource remain online past their commitment period, the Market Participant may submit updated mitigated Start-Up and mitigated No-Load Offers that reflect the procurement of higher cost fuel;

2. A Resource must switch fuels due to unforeseen operating conditions; or

3. The Resource is an ESR.

Intra-day changes to the mitigated Start-Up and mitigated No-Load offers must follow the mitigated offer development guidelines Appendix G of in the Market Protocols. Any such changes will be validated by the Market Monitor.

H. In all cases under this Section 3.3, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

3.3.1 Mitigation Measures for Transition State Offers

The mitigation measures in this section apply only to MCRs. A mitigated Transition State Offer shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines specified in the Market Protocols for each potential transition state changes. The
mitigated Transition State offer may be updated up to the close of the Day-Ahead Market before the Operating Day as defined in Section 5.1 of Attachment AE of this Tariff for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Transition State Offer may be updated until the Day-Ahead RUC process begins. The mitigated Transition State Offer submitted at the time the Day-Ahead RUC process begins will apply to the Day-Ahead RUC process on the day before the Operating Day and Intra-Day RUC processes on the Operating Day.

A. For an MCR that was not transitioned to address a Local Reliability Issue, the Transition State Offer conduct threshold is a 25% increase above the mitigated Transition State Offer.

B. For an MCR that was not transitioned to address a Local Reliability Issue, the Transmission Provider shall apply mitigation measures by replacing the Transition State Offer with the mitigated Transition State Offer if:

(1) The Resource’s Transition State Offer exceeds the mitigated Transition State Offer by the applicable conduct threshold; and

(2) The Resource has local market power as determined in Sections 3.1(1) or 3.1(2); and

(3) The Resource either:

(a) Fails the Market Impact Test as described in Section 3.7, or

(b) Is manually committed by the Transmission Provider or by a local transmission operator.

C. For an MCR that has local market power as determined in Section 3.1(3), the Transmission Provider shall apply mitigation measures by placing a cap on the Transition State Offer of 10% above the mitigated Transition State Offer.
D. The mitigated Transition State Offer for an MCR shall represent the costs of moving from the current configuration to another configuration as determined from the fuel costs incurred during the transition, the costs related to that fuel usage, Performance Factor, and additional maintenance and labor costs incurred during the transition, including transition VOM cost and transition major maintenance cost. Further guidelines for the mitigated Transition State Offer are documented in Appendix G of the Market Protocols.

The Market Participant shall submit documentation of the method and any cost data for calculating the mitigated Transition State Offer that is necessary to allow the Market Monitor to validate submitted offers. Further details associated with the development of these costs are included in the Market Protocols.

E. Intra-day changes to the mitigated Transition State Offers are allowed under the following conditions:

1. In the event that the Transmission Provider requests that a Resource remain online past their commitment period, the Market Participant may submit an updated mitigated Transition State Offer that reflects the procurement of higher cost fuel; or

2. A Resource must switch fuels due to unforeseen operating conditions.

Intra-day changes to the mitigated Transition State Offers must follow the mitigated offer development guidelines in Appendix G of the Market Protocols. Any such changes will be validated by the Market Monitor.

F. In all cases under this Section 3.3.1, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of the Tariff.
3.4 Mitigation Measures for Operating Reserve Offers

A mitigated offer for each Operating Reserve product shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. For MCRs for which a single configuration allows physical units to be swapped (e.g., Combustion Turbine 2 for Combustion Turbine 1), the costs used in the mitigated offer development for that configuration shall be those of the least cost physical unit that is available and can be swapped in such configuration. The mitigated Operating Reserve Offers may be updated up to the close of the Day-Ahead Market for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Operating Reserve Offers may be updated until the Day-Ahead RUC begins. For Resources committed by the Day-Ahead Market, the mitigated Operating Reserve Offers submitted as of the close of the Day-Ahead Market will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day unless an exception is allowed in Section 3.4(GI) of this Attachment AF; for all other Resources, the mitigated Operating Reserve Offers submitted at the time the Day-Ahead RUC begins will apply to the RTBM on the Operating Day.

A. For a Resource with an Operating Reserve Offer greater than or equal to $10/MWh that was not committed to address a Local Reliability Issue, the offer conduct threshold for each of the Operating Reserve products is a 25% increase above the mitigated offer for the applicable Operating Reserve Offer.

B. For a Resource with an Operating Reserve Offer greater than or equal to $10/MWh that was not committed to address a Local Reliability Issue, the Transmission Provider shall apply mitigation measures by replacing the Operating Reserve Offer with the applicable mitigated Operating Reserve Offer if:

(1) The Resource’s Operating Reserve Offer exceeds the applicable mitigated offer by the conduct threshold; and
(2) The Resource has local market power as determined in Sections 3.1(1) or 3.1(2); and

(3) The Resource either:

   (a) Fails the Market Impact Test as described in Section 3.7, or
   (b) Is manually committed by the Transmission Provider or by a local transmission operator.

A Resource with an Operating Reserve Offer below $10/MWh shall not be subject to mitigation measures on its applicable Operating Reserve Offer for economic withholding.

C. For a Resource with an Operating Reserve Offer greater than or equal to $10/MWh that has local market power as determined in Section 3.1(3), the Transmission Provider shall apply mitigation measures by placing a cap on the Operating Reserve Offer of 10% above the applicable mitigated Operating Reserve Offer. A Resource with an Operating Reserve Offer below $10/MWh shall not be subject to mitigation measures on its applicable Operating Reserve Offer for economic withholding.

D. The mitigated Spinning Reserve Offer shall be equal to zero for Resources other than combustion turbines, reciprocating engines and hydro Resources operating as a synchronous condenser. No known incremental costs are incurred for providing Spinning Reserves from other resource types.

Total mitigated Spinning Reserve Offer for combustion turbines, reciprocating engines and hydro Resources operating as a synchronous condenser shall not exceed any additional fuel related costs, maintenance costs and power consumption costs necessary for the Resource to be prepared for deployment of Spinning Reserve:

\[
\text{Mitigated Spinning Reserve Offer (}/\text{MW} \) \leq \\
(\text{Additional Fuel Cost (}/\text{Hr} \) + \text{Additional Maintenance Cost (}/\text{Hr} \) + Condensing Power Cost (}/\text{Hr} \) ) / \text{Spinning Reserve MW}
\]
The mitigated Supplemental Reserve Offer shall not exceed labor costs necessary for the Resource to be prepared for deployment of Supplemental Reserve:

\[
\text{Mitigated Supplemental Reserve Offer ($/MW) } \leq \frac{\text{Additional Labor Cost($)}}{\text{Average Supplemental Reserve MW}}
\]

E. The mitigated Regulation-Up Service Offer shall not exceed the sum of the cost increase due to:

(1) the heat rate increase during non-steady state operation,
(2) increase in VOM due to non-steady state operation,
(3) uncompensated costs, as described in the Market Protocols:

Where:

\[
\text{Mitigated Regulation-Up Service Offer} = \text{Mitigated Regulation-Up Offer ($/MW)} + \text{Mitigated Regulation-Up Mileage Offer ($/MW)},
\]

\[
\text{Mitigated Regulation-Up Offer ($/MW)} \leq \text{Uncompensated Cost ($/MW)},
\]

\[
\text{Mitigated Regulation-Up Mileage Offer ($/MW)} \leq (\text{Cost Increase due to a decreased energy conversion efficiency (e.g., Heat Rate Increase) during non-steady state operation + Cost Increase in VOM}) \times \text{Regulation-Up Mileage Factor}
\]

F. The mitigated Regulation-Down Service Offer shall not exceed the sum of the cost increase due to:

(1) the heat rate increase during non-steady state operation,
(2) increase in VOM due to non-steady state operation,
(3) uncompensated costs, as described in the Market Protocols:

Where:

\[
\text{Mitigated Regulation-Down Service Offer} = \text{Mitigated Regulation-Down Offer ($/MW)} + \text{Mitigated Regulation-Down Mileage Offer ($/MW)},
\]

\[
\text{Mitigated Regulation-Down Offer ($/MW)} \leq \text{Uncompensated Cost ($/MW)},
\]

and
Mitigated Regulation-Down Mileage Offer ($/MW) ≤
(Cost Increase due to a decreased energy conversion efficiency
(e.g., Heat Rate Increase) during non-steady state operation + Cost
Increase in VOM) * Regulation-Down Mileage Factor

Further details associated with the development of the exact costs in the
formulas above are included in the Market Protocols.

G. Ramp Capability Up, Ramp Capability Down, and online Uncertainty
Reserve products will not require mitigated offers, as the cost of these
products shall be the marginal cost of lost opportunity and not participant
Offers.

H. The mitigated offline Uncertainty Reserve Offers shall not exceed the
costs that shall not be eligible for reimbursement through a make whole
payment for Resources that clear offline Uncertainty Reserve, and are
committed to provide energy as a result of that clearing, as described in
Section 8.6.5 of Attachment AE of this Tariff. These costs shall be
amortized over the Resource’s expected Uncertainty Reserve megawatts
and Uncertainty Reserve response time:

\[
\text{Offline Uncertainty Reserve ($/MWh) = } ((\text{Start-Up Costs ($/Start) + No-Load Costs ($/hour)}*\text{Max(Uncertainty Reserve response time, Minimum Run Time) (hours) + Minimum Energy Costs during the larger of the Uncertainty Reserve response time and Minimum Run Time ($/Start))}) /(\text{Expected Uncertainty Megawatts * Uncertainty Reserve response time (hours))}).
\]

Expected uncertainty megawatts are derived from the total rampable
capacity that an offline resource can provide, from an offline state, during
the Uncertainty Reserve response time. This includes the ramp provided to
reach the Minimum Economic Capacity Operating Limit, plus any ramp
that can be provided to the market during the remaining Uncertainty
Reserve response time. For example, if a Resource has a 60 MWh ramp
rate, a Minimum Economic Capacity Operating Limit of 20 megawatts, a
Maximum Economic Capacity Operating Limit of 100 megawatts, and a
combined Start-Up Time and Sync-To-Min Time of 40 minutes, then the
expected Uncertainty Reserve megawatts will be 40 megawatts when the
Uncertainty Reserve response time is one hour. In this example, 20 megawatts came from the Resource reaching its economic minimum limit, then 20 megawatts came from the 20 minutes remaining in the Uncertainty Reserve response time [1 hour response time - (Start-Up Time + Sync-to-min)] multiplied by the one megawatt per minute ramp rate.

I. Intra-day changes to the mitigated Operating Reserve Offers are allowed under the following conditions:

1. In the event that the Transmission Provider requests that a Resource that is supplying Operating Reserves remain online past their commitment period by the Day-Ahead Market or a RUC process, the Market Participant may submit an updated mitigated Operating Reserve offer curve that reflects the procurement of higher cost fuel;

2. A Resource must switch fuels due to unforeseen operating conditions; or

3. Intra-day changes to the mitigated Regulation-Up and mitigated Regulation-Down Offers are allowed after the Day-Ahead RUC clears on the day before the Operating Day under the following condition:

   a. The Resource incurs the uncompensated cost in Section 3.4(E)(3) of this Attachment AF, for which the mitigated offer calculation is described in Appendix G of the Market Protocols.

Intra-day changes to the mitigated Operating Reserve Offer curve must follow the mitigated offer development guidelines in Appendix G and Section 8.2.2 of the Market Protocols. Any such changes will be validated by the Market Monitor.

HJ. The Market Participant may include in the calculation of its mitigated Operating Reserve Offer an amount reflecting the Resource-specific opportunity costs if the Market Participant is able to demonstrate to the satisfaction of the SPP Market Monitoring Unit that such costs are legitimate and verifiable and not otherwise included in market outcomes. To the extent such costs include run-time restrictions, such run-time restrictions shall be updated as specified in the Market Protocols, with more frequent updating to occur the fewer hours that remain available,
consistent with the Market Protocols. The formulas and instructions in the price forecast model for any such opportunity costs shall be determined by the SPP Market Monitoring Unit and published in the Market Protocols as part of the Mitigated Offer Development Guidelines, updated, as needed, by the SPP Market Monitoring Unit. Opportunity costs for mitigated Operating Reserve Offers shall not include Energy and Operating Reserve Markets revenues associated with forgone Energy or other types of Operating Reserve production to the extent that such costs are included in market outcomes.

IK. All cost data and cost calculation descriptions are subject to the review and approval of the SPP Market Monitoring Unit to ensure reasonableness and consistency across Market Participants. The information will be sufficient for replication of the mitigated Operating Reserve Offers and shall include, among other data, the following information:

(1) For fuel costs, Market Participants shall provide the Market Monitoring Unit with an explanation of the Market Participants’ fuel cost policy, indicating whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or referenced spot market prices. Any included fuel transportation and handling costs must be short-run marginal costs only, exclusive of fixed costs.

(2) For emissions costs, Market Participants shall report the emissions rate of each of their units and indicate the applicable emissions allowance cost.

(3) For VOM costs, Market Participants shall submit VOM costs, calculated in adherence with the Appendix G of the Market Protocols, reflecting short-run marginal costs, exclusive of fixed costs.

JL. In all cases under this Section 3.4, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.
3.5 Validation of Mitigated Resource Offer Parameters

The Market Monitor shall review the costs included in each mitigated Resource Offer on an ex-post basis relative to the relevant Operating Day in order to ensure that the Market Participant has correctly applied the formulas and definitions in Sections 3.2, 3.3.1, and 3.4 of this Attachment AF and in the Market Protocols and that the level of the mitigated offer is otherwise acceptable. If the mitigated offer determined by the Market Monitor and the Market Participant differ, Market Participant shall use the mitigated offer calculated by the Market Monitor going forward. If a Market Participant submits a dispute over its mitigated offer, the previously approved mitigated offer shall be used from the time the dispute is submitted until the dispute is resolved. The procedures for submitting and processing disputes related to mitigated offers shall be those specified in the Market Protocols. The Transmission Provider shall remedy mitigated offer disputes resolved in favor of the Market Participant by providing make whole payments, as necessary, to the Market Participant whose mitigated offer was improperly determined by the Market Monitor.

Each Market Participant is obligated to provide to the Market Monitor any cost data necessary to allow the Market Monitor to validate its mitigated Resource Offer.

The Market Monitor shall keep such data confidential, and all cost data submitted under this Section 3.5, including any opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff. The Market Monitor shall develop and maintain on the Transmission Provider’s website the mechanism and procedures to allow Market Participants to submit such cost data.

3.6 Additional Mitigation Measures for Resource Offer Parameters

The mitigation measures in this section apply to all Resource Offer parameters expressed in units other than dollars and will only apply in the presence of local market power as described in Section 3.1 of this Attachment AF. A reference level for each applicable Resource Offer parameter that reflects the physical capability of the Resource shall be determined prior to the start of the Energy and Operating Reserve Markets by one or both of the following methods: (i) the reference levels will be determined through consultation between the Market Participant and the Market Monitor; and/or (ii) the
reference levels will be based on averages of Resource Offer parameters from similar Resources. This methodology for setting reference levels for Offer parameters shall apply to all Resources at the start of the Energy and Operating Reserve Markets and to all Resources that register subsequent to the start of the Energy and Operating Reserve Markets. The Transmission Provider’s output forecast for a wind-powered Variable Energy Resource shall be used as the reference maximum output limit for the wind-powered Variable Energy Resource.

The following thresholds shall be used by the Transmission Provider to identify Resource Offers that may warrant mitigation and shall be determined with respect to the corresponding reference level:

Time-based Resource Offer parameters: An increase of three (3) hours, or an increase of six (6) hours in total for multiple time-based Resource Offer parameters.

Resource Offer parameters expressed in units other than time or dollars: One hundred percent (100%) increase for Resource Offer parameters that are minimum values, or a fifty percent (50%) decrease for Resource Offer parameters that are maximum values.

Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Maximum Charge Limit, as applicable, threshold for Resources committed to address a Local Reliability Issue: twenty-five percent (25%) increase.

Maximum Charge Limit, as applicable, threshold for Resources committed to address a Local Reliability Issue: twenty-five percent (25%) decrease.

In the case that a Resource Offer fails the thresholds described above, the Market Monitor shall determine the impact on prices or make whole payments. If an impact exceeds the LMP, MCP or make whole payment thresholds in Section 3.7, the Market Monitor will initiate a discussion with the Market Participant concerning an explanation of the parameter changes. The Market Monitor will inform the Transmission Provider of any potential issue. If the Transmission Provider, in consultation with the Market Monitor, concludes that the Market Participant has demonstrated the validity of the submitted Resource Offer parameter, no further action will be taken. If not, the
Transmission Provider shall replace the Resource Offer parameter with the corresponding reference level. Mitigation measures will remain in place until such time that the Market Participant demonstrates the validity of the Resource Offer parameter or the Market Participant notifies the Market Monitor that the Resource Offer parameter has been changed to a value that is within the tolerance range as described above, and the Market Monitor has verified that this change has occurred. In the event that the Market Participant submits a dispute, the mitigation measure will remain in place until the resolution of the dispute.

In all cases under this Section 3.6, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

3.7 Market Impact Test

The Transmission Provider will apply the following market impact test in the Day-Ahead Market, Day-Ahead RUC, Intra-Day RUC and Real-Time Balancing Market in the event the conditions described in Section 3.1 of this Attachment AF are satisfied:

After an initial market solution is computed with no mitigation measures in place, a second market solution, called the mitigated market solution, will be computed with the appropriate mitigation measures applied. With the exception of Ramp Capability Up and Ramp Capability Down, if an LMP or MCP at a Settlement Location from the initial market solution exceeds the corresponding price from the mitigated market solution by the applicable impact test threshold, or a make whole payment for any Resource from the initial market solution exceeds the corresponding make whole payment from the mitigated market solution by make whole payment impact test threshold, then the mitigated market solution will be used for dispatch, commitment, and settlement purposes.

The LMP impact threshold is twenty-five dollars ($25) per megawatt hour, the MCP impact threshold is twenty-five dollars ($25) per megawatt hour, and the make whole payment impact threshold is twenty-five dollars ($25) per megawatt hour.

3.8 Mitigation Exceptions
A. The Market Monitor shall, as soon as practicable and if warranted in light of the information available to the Market Monitor, contact a Market Participant to request an explanation of its actions in cases when an impact threshold in Section 3.7 of this Attachment AF is exceeded and the Market Participant’s offer exceeded the mitigated offer by more than the applicable conduct threshold, as specified in Section 3.2, 3.3, 3.3.1, or 3.4 of this Attachment AF.

3.9 Sanctions for Noncompliance with the Day-Ahead Market Must Offer Requirement

A. In the case that a Market Participant is found to be noncompliant for an Asset Owner as determined by the conditions set forth in Section 2.11.1 of Attachment AE, the Market Participant shall be assessed a penalty for that Asset Owner by the Transmission Provider for each megawatt of withheld capacity below the 10% tolerance band. The penalty amount shall be equal to the Day-Ahead Market LMP associated with the withheld capacity.

B. The Market Monitor will monitor for, and report to the Commission’s Office of Enforcement, or its successor organization, manipulative behavior associated with Day-Ahead Offers, including (but not limited to) monitoring load-serving Market Participants who do not offer enough net resource capacity to meet their maximum hourly Reported Load. The Market Monitor will also report to the Commission’s Office of Enforcement or its successor organization any locational problems, such as deliverability issues, associated with load-serving Market Participants’ offers in the Day-Ahead Market, any identified efforts by Market Participants to raise prices in the RTBM by limiting Day-Ahead Offers, and the effects of any such efforts upon make whole payments.
ADDENDUM 1 TO ATTACHMENT AO

AGREEMENT ESTABLISHING A PSEUDO-TIE ELECTRICAL INTERCONNECTION POINT WHERE THERE IS NO APPLICABLE JOINT OPERATING AGREEMENT WITH AN EXTERNAL BALANCING AUTHORITY

This Agreement Establishing a Pseudo-Tie Electrical Interconnection Point (including its exhibits, this “Agreement”) is entered into this ____ day of _____________ 20____ by and among ____________(“External Balancing Authority”), ______________(“Market Participant”), and the Southwest Power Pool, Inc. (“SPP”). External Balancing Authority, Market Participant and SPP are hereinafter referred to individually as a “Party” and collectively as the “Parties.”

WHEREAS, in order to facilitate the foregoing, the Parties desire to establish a new pseudo-tie electrical interconnection point between the SPP Balancing Authority and the External Balancing Authority on the terms and conditions set forth in this Agreement; and

WHEREAS, there are no terms or conditions in a joint operating agreement or any other agreement that specifies the coordination between the SPP Balancing Authority and the External Balancing Authority for pseudo-tie electrical interconnection points between the SPP Balancing Authority and the External Balancing Authority; and

WHEREAS, SPP is a Regional Transmission Organization approved by the Federal Energy Regulatory Commission operating an Integrated Marketplace and is a NERC certified Balancing Authority; and

WHEREAS, the External Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant to the SPP Balancing Authority as defined below or the External Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined below; and

WHEREAS, the Market Participant is responsible for generation or load outside of the boundaries of the SPP Balancing Authority Area and desires to participate in the Integrated Marketplace as a Resource or load or the Market Participant is responsible for generation or load inside the SPP Balancing Authority Area and desires not to participate in the Integrated Marketplace; and

WHEREAS, the SPP Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant from the External Balancing Authority as defined below or the SPP Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined below; and
WHEREAS, Market Participant represents the generator or load serving entity that is physically located within the balancing authority boundaries of the External Balancing Authority or the SPP Balancing Authority; and

WHEREAS, Market Participant represents the generator or load serving entity registered with SPP and meeting all of the SPP qualifications in order to operate in the Integrated Marketplace and abiding by all the respective Market Protocols and rules as set forth by SPP.

NOW THEREFORE, in consideration of the mutual covenants and agreements in this Agreement and of other good and valuable consideration, the sufficiency and adequacy of which are hereby acknowledged, the Parties, intending to be legally bound, hereby agree as follows:

1. **Creation of Pseudo-Tie Point.** From and after the effective date hereof, the point at which pseudo-tie electrical interconnection is made between the Market Participant ____________ (Name of the generation or load) ____________ (generation or load location) (the “Facility”) and the SPP Balancing Authority, which shall be defined in the one-line diagram attached hereto as Exhibit A, shall be a new pseudo-tie electrical interconnection point between the SPP Balancing Authority and the External Balancing Authority (the “Pseudo-Tie Point”), whereby any energy delivered from or consumed by the Facility at the Pseudo-Tie Point shall be treated as a balancing authority interchange between the External Balancing Authority and the SPP Balancing Authority (for the avoidance of doubt, whether or not, at the time of delivery or consumption of such energy, the metering, data processing, telemetry and other equipment associated with the Pseudo-Tie Point is properly functioning). For the avoidance of doubt, the SPP Balancing Authority or the External Balancing Authority will not be taking title to any energy delivered from or consumed by the Facility at the Pseudo-Tie Point.

2. **Implementation.** Each Party shall design, construct, operate and maintain the equipment for which it is responsible under this Agreement, and shall take all other actions required of it, to create and have the Pseudo-Tie Point recognized by the SPP as a balancing authority interchange between the External Balancing Authority and the SPP Balancing Authority for the purpose of allowing the Facility to be treated as being in the SPP Balancing Authority or the External Balancing Authority. Without limiting the foregoing, each Party shall undertake the design, construction, operation and maintenance for which it is responsible under this Agreement according to North American Electric Reliability Corporation standards. A basic block diagram of the communications equipment required for the Pseudo-Tie Point is set forth in Exhibit B. As among the Parties:

   (a) The entity representing the generator or load in the External Balancing Authority or the generator or load within the SPP Balancing Authority shall register with SPP to become a Market Participant in the Integrated Marketplace. Registration shall be done in accordance with the SPP Market Protocols. Each Facility must be registered separately with SPP and registration information shall be provided to the External Balancing Authority. Market Participant must register its generator or load located in the External Balancing Authority or its generator or load located in the SPP Balancing Authority.
(b) This Agreement does not provide for the reservation or sale of transmission service under the SPP’s Open Access Transmission Tariff or on any other transmission system. Market Participant shall secure and pay for all cost associated with transmission service, across all transmission service providers necessary to deliver or consume power from the Facility to the interface point with the SPP Balancing Authority or to the interface point with the External Balancing Authority.

(c) In order to supply Energy and qualified Operating Reserve products (Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, and/or Ramp Capability Down, and/or Uncertainty Reserve) to the Integrated Marketplace or to transfer load to the Integrated Marketplace, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the SPP Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting participation and for continued participation in the Energy and Operating Reserve Markets.

(d) In order to supply energy to the External Balancing Authority or to transfer load to the External Balancing Authority, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the External Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting approval of the movement of Resources and load out of the SPP Balancing Authority to the External Balancing Authority.

(e) Market Participant is solely responsible for all requirements as set forth for a Market Participant in the Market Protocols.

(f) Market Participant shall design, construct, operate and maintain systems and communications equipment in order to: (i) receive SPP deployment instructions for generators pseudo-tying into the SPP Balancing Authority; (ii) account for load pseudo-tying into the SPP Balancing Authority; and (iii) enable SPP to account for congestion and losses associated with generators and loads pseudo-tying out of the SPP Balancing Authority in accordance with the Market Protocols.

(g) Market Participant shall design, construct, operate and maintain real-time and historical systems and communications equipment, at Market Participant’s expense, in order to provide the External Balancing Authority and the SPP Balancing Authority with the corresponding real-time pseudo-tie value. Market Participant’s systems shall provide this signal to the SPP Balancing Authority per the SPP Balancing Authority’s ICCP communication standards. Market Participant’s system shall provide this signal to the External Balancing Authority in a manner mutually agreed to between the External Balancing Authority and the Market Participant.

(h) SPP, in accordance with the Market Protocols, will provide the Market Participant commitment and dispatch instructions for generators pseudo-tying into the SPP
Balancing Authority for participation in the Energy and Operating Reserve Markets consistent with such instructions issued to other registered Resources.

(i) For generators pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.

(j) For generators pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(k) For loads pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.

(l) For loads pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(m) The External Balancing Authority and the SPP Balancing Authority will include the real time pseudo-tie value in their respective calculations of Net Actual Interchange and Area Control Error.

(n) If communication is lost between any of the Parties (including communication between SPP and the Market Participant), the External Balancing Authority and the SPP Balancing Authority will freeze at the last known value and it is the responsibility of the Market Participant to verbally communicate changes of the real time pseudo-tie values with the other Parties.

(o) Market Participant shall notify the other Parties of any real-time circumstances that affect the Market Participant’s obligation or ability to meet the SPP Setpoint Instructions or External Balancing Authority instructions. A generator pseudo-tying into the SPP Balancing Authority will be subject to the same penalties as a Resource under Attachment AE of the SPP Tariff. A generator pseudo-tying out of the SPP Balancing Authority will be subject to the rules and procedures specified by the External Balancing Authority.

(p) The External Balancing Authority and the SPP Balancing Authority shall integrate the real time pseudo-tie value on an hourly basis and maintain this information for balancing authority checkout, inadvertent calculations and payback purposes in accordance with the applicable NERC standards. For generators and loads pseudo-tying into the SPP Balancing Authority, it is the responsibility of the External
Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the External Balancing Authority’s final daily checkout with the SPP Balancing Authority. For generators and loads pseudo-tying out of the SPP Balancing Authority, it is the responsibility of the SPP Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the SPP Balancing Authority’s final daily checkout with the External Balancing Authority.

(q) The Market Participant for generators and loads pseudo-tying into or out of the SPP Balancing Authority Area is responsible for submission of settlement meter data for use in the settlement process of the Real-Time Balancing Market in accordance with the SPP Market Protocols.

(r) Except as otherwise provided in this Section 2, failure by the Market Participant to provide real-time pseudo-tie values in a timely manner constitutes a basis for the immediate suspension of this Agreement by the External Balancing Authority or the SPP Balancing Authority. In the event of such suspension, the Market Participant shall provide a remedy for the cause of the failure prior to resumption of participation. In the event of two suspensions within a thirty day period, this Agreement may be terminated, in accordance with Section 7 of this Agreement, at the sole discretion of the External Balancing Authority or the SPP Balancing Authority.

3. **Losses.** For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will be responsible for loss compensation to transmission provider(s) to deliver their energy to or receive their energy from the SPP Balancing Authority. Pseudo-tie value(s) will be considered net of losses external to SPP. Losses within the SPP Balancing Authority attributable to the Market Participant’s participation in the Energy and Operating Reserve Markets, including generators and loads pseudo-tying out of the SPP Balancing Authority, shall be handled in the same manner as other Energy and Operating Reserve Markets transactions.

4. **Compensation.** For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will compensate the External Balancing Authority for the reasonable implementation and operations related costs borne by the External Balancing Authority as a result of this Agreement unless the Market Participant and External Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement. For generators and loads pseudo-tying out of the SPP Balancing Authority, Market Participant will compensate the SPP Balancing Authority for the reasonable implementation and operations related costs borne by the SPP Balancing Authority as a result of this Agreement unless the Market Participant and SPP Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement.

5. **Auditing.** Each Party reserves the right to audit records necessary to permit evaluation and verification of claims submitted, and the other Party’s compliance with this Agreement. The Parties shall retain for a period of three years all information and records relating to the performance of this Agreement. Each Party may examine and copy such information and
records at the other Party’s premises during regular business hours and upon advance notice given no less than 15 calendar days prior to such examination.

6. **Effective Date.** The Agreement is effective upon full execution if it is not filed with the Commission. If the Agreement is filed with the Commission, then it is effective upon the later of the date of execution or the date allowed by the Commission. If the parties are unable to resolve any issues, SPP shall file an unexecuted agreement with the Commission, including all agreed-upon non-conforming deviations.

7. **Termination.** Other than as provided in Section 2(r), this Agreement shall terminate on ________(Date), unless extended by agreement of all the Parties. Any Party shall have the right to terminate this Agreement upon ___ month’s notice, subject to receiving all necessary regulatory approvals for such termination.

8. **Governing Law.** The interpretation and performance of this Agreement and each of its provisions shall be governed and construed in accordance with the applicable Federal and/or State laws without regard its conflicts of laws provisions that would apply the laws of another jurisdiction.

9. **Interpretation.** In this Agreement:

   (a) the words “include”, “includes” and “including” are deemed to be followed by the words “without limitation”;

   (b) references to contracts, agreements and other documents and instruments shall be references to the same as amended, supplemented or otherwise modified from time to time;

   (c) references to laws or standards and to terms defined in, and other provisions of, laws or standards shall be references to the same (or a successor to the same) as amended, supplemented or otherwise modified from time to time; and

   (d) references to a person shall include its successors and permitted assigns and, in the case of a governmental or other authority (including SPP and the North American Electric Reliability Corporation), any person succeeding to its functions and capacities.

10. **Severability.** If any provision of this Agreement is held invalid, illegal or unenforceable in any jurisdiction, then, the Parties agree, to the fullest extent permitted by law, that the validity, legality and enforceability of the remaining provisions hereof in such or any other jurisdiction and of such provision in any other jurisdiction shall not in any way be affected or impaired thereby. With respect to the provision held invalid, illegal or unenforceable, the Parties will amend this Agreement as necessary to effect the original intent of the Parties as closely as possible.
11. **Complete Agreement; Amendments.** This Agreement constitutes the entire agreement among the Parties with respect to the subject matter of this Agreement and supersedes other prior agreements and understandings, both written and oral, among the Parties with respect to the subject matter of this Agreement. This Agreement may be amended, supplemented or otherwise modified only by an instrument in writing signed by all Parties.

12. **Other Obligations.** Nothing in this Agreement is intended to modify or change any obligations or rights under any tariff (including the SPP Tariff), any rate schedule, or any other contract. This Agreement does not in any way provide transmission service or address rates, terms or conditions of transmission service or indicate in any way that transmission service is available or properly awarded. A Party seeking transmission service must still go through the full tariff process to obtain transmission service. This Agreement also does not establish any generation as a designated network resource under the Tariff; the requirements of the Tariff still must be satisfied. Nor does this Agreement make any Party a Market Participant under the SPP Tariff. A Party seeking to become a Market Participant must apply to SPP under the terms of the SPP Tariff and nothing in this Agreement affects its rights or obligations as a Market Participant.

13. **Commission Filing.** If unchanged, a signed version of this form agreement shall not be filed with the Commission. SPP will simply report the existence of a signed agreement in its quarterly reports. If the form agreement is substantively changed, then SPP shall file the revised form agreement with the Commission. The Parties shall be bound to the terms accepted or ordered by the Commission.

14. **Modification.** Nothing in this Agreement is intended to modify or limit the right of SPP to submit under FPA Section 205 or Section 206 unilateral changes to this Agreement (both the form Agreement and any signed agreement); the right of any other Party to seek unilateral changes under FPA Section 206, or the right of the Federal Energy Regulatory Commission to accept any FPA Section 205 filing or to make changes under FPA Section 206 or to initiate proceedings under FPA Section 206.

15. **Charges.** The provisions in this Agreement providing for compensation do not authorize Commission regulated public utilities to impose charges without a separately filed tariff or rate schedule being accepted by the Commission.

16. **Disputes.** Any disputes under this Agreement shall first be resolved pursuant to the dispute resolution procedures in the SPP’s Open Access Transmission Tariff. Any disputes may be brought to the Commission.

17. **Breach.** If any Party breaches the terms of this Agreement, then a non-breaching Party may seek any relief it believes is appropriate at the Commission. A breach is considered a substantive violation of this Agreement. Prior to pursuing a remedy at the Commission for a breach, a non-breaching Party shall provide five business days notice of the breach to the breaching Party. If the breaching Party does not eliminate the breach within five (5) business days after the notice is received by the breaching Party, then the non-breaching Party may pursue its remedies at the Commission.
18. **Counterparts.** This Agreement may be executed in one or more counterparts, each of which shall be an original but all of which, taken together, shall constitute only one legal instrument. It shall not be necessary in making proof of this Agreement to produce or account for more than one counterpart. The delivery of an executed counterpart of this Agreement by facsimile shall be deemed to be valid delivery thereof.
The Parties have caused this Agreement to be signed by their authorized representatives on the day and year first above written.

**External Balancing Authority**

By:_____________________________
   Name:_____________________
   Title:_____________________

**SPP Balancing Authority**

By:_____________________________
   Name:_____________________
   Title:_____________________

**Market Participant**

By:_____________________________
   Name:_____________________
   Title:_____________________
EXHIBIT A
ONE-LINE DIAGRAM
EXHIBIT B
BLOCK DIAGRAM
AGREEMENT ESTABLISHING A PSEUDO-TIE ELECTRICAL INTERCONNECTION POINT WHERE THERE IS AN APPLICABLE JOINT OPERATING AGREEMENT WITH AN EXTERNAL BALANCING AUTHORITY

This Agreement Establishing a Pseudo-Tie Electrical Interconnection Point (including its exhibits, this “Agreement”) is entered into this ____ day of ____________ 20____ between ______________ (“Market Participant”) and the Southwest Power Pool, Inc. (“SPP”). Market Participant and SPP are hereinafter referred to individually as a “Party” and collectively as the “Parties.”

WHEREAS, in order to facilitate the foregoing, the Parties desire to establish a new pseudo-tie electrical interconnection point between the SPP Balancing Authority and ______________ (“External Balancing Authority”) on the terms and conditions set forth in this Agreement; and

WHEREAS, SPP is a Regional Transmission Organization approved by the Federal Energy Regulatory Commission operating an Integrated Marketplace and is a NERC certified Balancing Authority; and

WHEREAS, the External Balancing Authority and the SPP Balancing Authority are parties to the Commission approved SPP - ______________ [Name of the External Balancing Authority] Joint Operating Agreement (“JOA”) and the JOA specifies the coordination between the SPP Balancing Authority and the External Balancing Authority for pseudo-tie electrical interconnection points between the SPP Balancing Authority and the External Balancing Authority; and

WHEREAS, the External Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant to the SPP Balancing Authority as defined in the JOA or the External Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined in the JOA; and

WHEREAS, the Market Participant is responsible for generation or load outside of the boundaries of the SPP Balancing Authority Area and desires to participate in the Integrated Marketplace as a Resource or load or the Market Participant is responsible for generation or load inside the SPP Balancing Authority Area and desires not to participate in the Integrated Marketplace; and

WHEREAS, the SPP Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant from the External Balancing Authority as defined in the JOA or the SPP Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined in the JOA; and
WHEREAS, Market Participant represents the generator or load serving entity that is physically located within the balancing authority boundaries of the External Balancing Authority or the SPP Balancing Authority; and

WHEREAS, Market Participant represents the generator or load serving entity registered with SPP and meeting all of the SPP qualifications in order to operate in the Integrated Marketplace and abiding by all the respective Market Protocols and rules as set forth by SPP.

NOW THEREFORE, in consideration of the mutual covenants and agreements in this Agreement and of other good and valuable consideration, the sufficiency and adequacy of which are hereby acknowledged, the Parties, intending to be legally bound, hereby agree as follows:

1. **Creation of Pseudo-Tie Point.** From and after the effective date hereof, the point at which pseudo-tie electrical interconnection is made between the Market Participant ____________ (Name of the generation or load) ____________ (generation or load location) (the “Facility”) and the SPP Balancing Authority, which shall be defined in the one-line diagram attached hereto as Exhibit A, shall be a new pseudo-tie electrical interconnection point between the SPP Balancing Authority and the External Balancing Authority (the “Pseudo-Tie Point”), whereby any energy delivered from or consumed by the Facility at the Pseudo-Tie Point shall be treated as a balancing authority interchange between the External Balancing Authority and the SPP Balancing Authority (for the avoidance of doubt, whether or not, at the time of delivery or consumption of such energy, the metering, data processing, telemetry and other equipment associated with the Pseudo-Tie Point is properly functioning). For the avoidance of doubt, the SPP Balancing Authority or the External Balancing Authority will not be taking title to any energy delivered from or consumed by the Facility at the Pseudo-Tie Point.

2. **Implementation.** Each Party shall design, construct, operate and maintain the equipment for which it is responsible under this Agreement, and shall take all other actions required of it, to create and have the Pseudo-Tie Point recognized by the SPP as a balancing authority interchange between the External Balancing Authority and the SPP Balancing Authority for the purpose of allowing the Facility to be treated as being in the SPP Balancing Authority or the External Balancing Authority. Without limiting the foregoing, each Party shall undertake the design, construction, operation and maintenance for which it is responsible under this Agreement according to North American Electric Reliability Corporation standards. A basic block diagram of the communications equipment required for the Pseudo-Tie Point is set forth in Exhibit B. As among the Parties:

   (a) The entity representing the generator or load in the External Balancing Authority or the generator or load within the SPP Balancing Authority shall register with SPP to become a Market Participant in the Integrated Marketplace. Registration shall be done in accordance with the SPP Market Protocols. Each Facility must be registered separately with SPP and registration information shall be provided to the External Balancing Authority. Market Participant must register its generator or load located in the External Balancing Authority or its generator or load located in the SPP Balancing Authority.
(b) This Agreement does not provide for the reservation or sale of transmission service under the SPP’s Open Access Transmission Tariff or on any other transmission system. Market Participant shall secure and pay for all cost associated with transmission service, across all transmission service providers necessary to deliver or consume power from the Facility to the interface point with the SPP Balancing Authority or to the interface point with the External Balancing Authority.

(c) In order to supply Energy and qualified Operating Reserve products (Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, and/or Ramp Capability Down, and/or Uncertainty Reserve) to the Integrated Marketplace or to transfer load to the Integrated Marketplace, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the SPP Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting participation and for continued participation in the Energy and Operating Reserve Markets.

(d) In order to supply energy to the External Balancing Authority or to transfer load to the External Balancing Authority, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the External Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting approval of the movement of Resources and load out of the SPP Balancing Authority to the External Balancing Authority.

(e) Market Participant is solely responsible for all requirements as set forth for a Market Participant in the Market Protocols.

(f) Market Participant shall design, construct, operate and maintain systems and communications equipment in order to: (i) receive SPP deployment instructions for generators pseudo-tying into the SPP Balancing Authority; (ii) account for load pseudo-tying into the SPP Balancing Authority; and (iii) enable SPP to account for congestion and losses associated with generators and loads pseudo-tying out of the SPP Balancing Authority in accordance with the Market Protocols.

(g) Market Participant shall design, construct, operate and maintain real-time and historical systems and communications equipment, at Market Participant’s expense, in order to provide the External Balancing Authority and the SPP Balancing Authority with the corresponding real-time pseudo-tie value. Market Participant’s systems shall provide this signal to the SPP Balancing Authority per the SPP Balancing Authority’s ICCP communication standards. Market Participant’s system shall provide this signal to the External Balancing Authority in a manner mutually agreed to between the External Balancing Authority and the Market Participant.
(h) SPP, in accordance with the Market Protocols, will provide the Market Participant commitment and dispatch instructions for generators pseudo-tying into the SPP Balancing Authority for participation in the Energy and Operating Reserve Markets consistent with such instructions issued to other registered Resources.

(i) For generators pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.

(j) For generators pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(k) For loads pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.

(l) For loads pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(m) The SPP Balancing Authority will coordinate with the External Balancing Authority to include the real time pseudo-tie value in their respective calculations of Net Actual Interchange and Area Control Error as required by the JOA.

(n) If communication is lost between any of the Parties (including communication between SPP and the Market Participant), the External Balancing Authority and the SPP Balancing Authority will freeze at the last known value, as required by the JOA, and it is the responsibility of the Market Participant to verbally communicate changes of the real time pseudo-tie values with SPP and the External Balancing Authority.

(o) Market Participant shall notify SPP and the External Balancing Authority of any real-time circumstances that affect the Market Participant’s obligation or ability to meet the SPP Setpoint Instructions or External Balancing Authority instructions. A generator pseudo-tying into the SPP Balancing Authority will be subject to the same penalties as a Resource under Attachment AE of the SPP Tariff. A generator pseudo-tying out of the SPP Balancing Authority will be subject to the rules and procedures specified by the External Balancing Authority.

(p) The SPP Balancing Authority will coordinate with the External Balancing Authority to integrate the real time pseudo-tie value on an hourly basis and maintain this
information for balancing authority checkout, inadvertent calculations and payback purposes in accordance with the applicable NERC standards, as required by the JOA. For generators and loads pseudo-tying into the SPP Balancing Authority, it is the responsibility of the External Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the External Balancing Authority’s final daily checkout with the SPP Balancing Authority. For generators and loads pseudo-tying out of the SPP Balancing Authority, it is the responsibility of the SPP Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the SPP Balancing Authority’s final daily checkout with the External Balancing Authority.

(q) The Market Participant for generators and loads pseudo-tying into or out of the SPP Balancing Authority Area is responsible for submission of settlement meter data for use in the settlement process of the Real-Time Balancing Market in accordance with the SPP Market Protocols.

(r) Except as otherwise provided in this Section 2, failure by the Market Participant to provide real-time pseudo-tie values in a timely manner constitutes a basis for the immediate suspension of this Agreement by the SPP Balancing Authority. In the event of such suspension, the Market Participant shall provide a remedy for the cause of the failure prior to resumption of participation. In the event of two suspensions within a thirty day period, this Agreement may be terminated, in accordance with Section 7 of this Agreement, at the sole discretion of the SPP Balancing Authority.

3. **Losses.** For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will be responsible for loss compensation to transmission provider(s) to deliver their energy to or receive their energy from the SPP Balancing Authority. Pseudo-tie value(s) will be considered net of losses external to SPP. Losses within the SPP Balancing Authority attributable to the Market Participant’s participation in the Energy and Operating Reserve Markets, including generators and loads pseudo-tying out of the SPP Balancing Authority, shall be handled in the same manner as other Energy and Operating Reserve Markets transactions.

4. **Compensation.** For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will compensate the External Balancing Authority for the reasonable implementation and operations related costs borne by the External Balancing Authority as a result of this Agreement unless the Market Participant and External Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement. For generators and loads pseudo-tying out of the SPP Balancing Authority, Market Participant will compensate the SPP Balancing Authority for the reasonable implementation and operations related costs borne by the SPP Balancing Authority as a result of this Agreement unless the Market Participant and SPP Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement.

5. **Auditing.** Each Party reserves the right to audit records necessary to permit evaluation and verification of claims submitted, and the other Party’s compliance with this Agreement. The
Parties shall retain for a period of three years all information and records relating to the performance of this Agreement. Each Party may examine and copy such information and records at the other Party’s premises during regular business hours and upon advance notice given no less than 15 calendar days prior to such examination.

6. **Effective Date.** The Agreement is effective upon full execution if it is not filed with the Commission. If the Agreement is filed with the Commission, then it is effective upon the later of the date of execution or the date allowed by the Commission. If the parties are unable to resolve any issues, SPP shall file an unexecuted agreement with the Commission, including all agreed-upon non-conforming deviations.

7. **Termination.** Other than as provided in Section 2(r), this Agreement shall terminate on ________(Date), unless extended by agreement of all the Parties. Any Party shall have the right to terminate this Agreement upon ___ month’s notice, subject to receiving all necessary regulatory approvals for such termination.

8. **Governing Law.** The interpretation and performance of this Agreement and each of its provisions shall be governed and construed in accordance with the applicable Federal and/or State laws without regard its conflicts of laws provisions that would apply the laws of another jurisdiction.

9. **Interpretation.** In this Agreement:

   (a) the words “include”, “includes” and “including” are deemed to be followed by the words “without limitation”;

   (b) references to contracts, agreements and other documents and instruments shall be references to the same as amended, supplemented or otherwise modified from time to time;

   (c) references to laws or standards and to terms defined in, and other provisions of, laws or standards shall be references to the same (or a successor to the same) as amended, supplemented or otherwise modified from time to time; and

   (d) references to a person shall include its successors and permitted assigns and, in the case of a governmental or other authority (including SPP and the North American Electric Reliability Corporation), any person succeeding to its functions and capacities.

10. **Severability.** If any provision of this Agreement is held invalid, illegal or unenforceable in any jurisdiction, then, the Parties agree, to the fullest extent permitted by law, that the validity, legality and enforceability of the remaining provisions hereof in such or any other jurisdiction and of such provision in any other jurisdiction shall not in any way be affected or impaired thereby. With respect to the provision held invalid, illegal or unenforceable, the Parties will
amend this Agreement as necessary to effect the original intent of the Parties as closely as possible.

11. Complete Agreement; Amendments. This Agreement constitutes the entire agreement among the Parties with respect to the subject matter of this Agreement and supersedes other prior agreements and understandings, both written and oral, among the Parties with respect to the subject matter of this Agreement. This Agreement may be amended, supplemented or otherwise modified only by an instrument in writing signed by all Parties.

12. Other Obligations. Nothing in this Agreement is intended to modify or change any obligations or rights under any tariff (including the SPP Tariff), any rate schedule, or any other contract. This Agreement does not in any way provide transmission service or address rates, terms or conditions of transmission service or indicate in any way that transmission service is available or properly awarded. A Party seeking transmission service must still go through the full tariff process to obtain transmission service. This Agreement also does not establish any generation as a designated network resource under the Tariff; the requirements of the Tariff still must be satisfied. Nor does this Agreement make any Party a Market Participant under the SPP Tariff. A Party seeking to become a Market Participant must apply to SPP under the terms of the SPP Tariff and nothing in this Agreement affects its rights or obligations as a Market Participant.

13. Commission Filing. If unchanged, a signed version of this form agreement shall not be filed with the Commission. SPP will simply report the existence of a signed agreement in its quarterly reports. If the form agreement is substantively changed, then SPP shall file the revised form agreement with the Commission. The Parties shall be bound to the terms accepted or ordered by the Commission.

14. Modification. Nothing in this Agreement is intended to modify or limit the right of SPP to submit under FPA Section 205 or Section 206 unilateral changes to this Agreement (both the form Agreement and any signed agreement); the right of any other Party to seek unilateral changes under FPA Section 206, or the right of the Federal Energy Regulatory Commission to accept any FPA Section 205 filing or to make changes under FPA Section 206 or to initiate proceedings under FPA Section 206.

15. Charges. The provisions in this Agreement providing for compensation do not authorize Commission regulated public utilities to impose charges without a separately filed tariff or rate schedule being accepted by the Commission.

16. Disputes. Any disputes under this Agreement shall first be resolved pursuant to the dispute resolution procedures in the SPP’s Open Access Transmission Tariff. Any disputes may be brought to the Commission.

17. Breach. If any Party breaches the terms of this Agreement, then a non-breaching Party may seek any relief it believes is appropriate at the Commission. A breach is considered a substantive violation of this Agreement. Prior to pursuing a remedy at the Commission for a breach, a non-breaching Party shall provide five business days notice of the breach to the breaching Party. If the breaching Party does not eliminate the breach within five (5) business
days after the notice is received by the breaching Party, then the non-breaching Party may pursue its remedies at the Commission.

18. **Counterparts.** This Agreement may be executed in one or more counterparts, each of which shall be an original but all of which, taken together, shall constitute only one legal instrument. It shall not be necessary in making proof of this Agreement to produce or account for more than one counterpart. The delivery of an executed counterpart of this Agreement by facsimile shall be deemed to be valid delivery thereof.

The Parties have caused this Agreement to be signed by their authorized representatives on the day and year first above written.

**SPP Balancing Authority**

By:_____________________________
   Name:_________________________
   Title:__________________________

**Market Participant**

By:_____________________________
   Name:_________________________
   Title:__________________________
EXHIBIT A
ONE-LINE DIAGRAM
EXHIBIT B
BLOCK DIAGRAM