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February 26, 2014

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. ER12-1179-___**
SPP Integrated Marketplace Compliance Filing

Pursuant to the Federal Energy Regulatory Commission's ("Commission") Order on Compliance Filing issued on January 29, 2014,[1] Southwest Power Pool, Inc. ("SPP") submits revisions to its Open Access Transmission Tariff[2] and provides explanations in compliance with the January 2014 Order. SPP requests an effective date of March 1, 2014 for the Tariff revisions submitted in this filing.

I. BACKGROUND

On February 29, 2012, as amended on May 15, 2012, SPP submitted to the Commission proposed revisions to its Tariff to transition from its current Real-Time Energy Imbalance Service Market to the SPP Integrated Marketplace in March of 2014.[3] The Integrated Marketplace includes (among other things) Day-Ahead and Real-Time Energy and Operating Reserve Markets, a Transmission Congestion Rights market, and the formation of a new SPP Balancing Authority to consolidate and assume the responsibilities of the 16 separate Balancing Authority Areas currently operating within the SPP footprint. SPP requested a March 1, 2014 effective date for the implementation of the Integrated Marketplace.

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1 *Sw. Power Pool, Inc.*, 146 FERC ¶ 61,050 (2014) ("January 2014 Order").

2 Southwest Power Pool, Inc., FERC Electric Tariff, Sixth Revised Volume No. 1 ("Tariff"). In this letter, SPP refers to Tariff revisions submitted in this filing as "Revised Tariff." SPP refers to Tariff provisions previously accepted by the Commission effective March 1, 2014 as "Tariff."

3 Submission of Tariff Revisions to Implement SPP Integrated Marketplace, Docket No. ER12-1179-000 (Feb. 29, 2012) ("Integrated Marketplace Filing"); Amendatory Filing of Tariff Revisions to Implement SPP Integrated Marketplace, Docket No. ER12-1179-001 (dated May 15, 2012).

On October 18, 2012, the Commission conditionally approved SPP's Integrated Marketplace, and directed SPP to submit numerous revisions to its Tariff to "ensure that a well-designed market will be in place at the proposed effective date [of March 1, 2014]."[4] On February 15, 2013, SPP submitted revisions to its Tariff and provided explanations in compliance with the October 2012 Order.[5] On March 28, 2013, SPP submitted additional revisions to its Tariff pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d, to modify, clarify, and supplement several components of the Integrated Marketplace.[6] On April 19, 2013, SPP submitted revisions to its Tariff in compliance with the Integrated Marketplace Rehearing Order.[7]

On September 20, 2013, the Commission issued an order conditionally accepting in part and rejecting in part SPP's proposed Tariff revisions to comply with the October 2012 Order.[8] The Commission further found that SPP complied with the Commission's directives in the Integrated Marketplace Rehearing Order and accepted SPP's April 2013 Compliance Filing.[9] Finally, the Commission accepted in part and rejected in part the Tariff revisions submitted in the March 2013 Filing and conditionally accepted SPP's Readiness Plan and Reversion Plan submitted on March 28, 2013.[10]

On November 11, 2013, SPP submitted a filing to comply with the directives of the September 2013 Order.[11] On November 15, 2013, SPP submitted an additional filing revising certain limited aspects of its Integrated Marketplace, to modify, clarify, and

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4 *Sw. Power Pool, Inc.*, 141 FERC ¶ 61,048, at P 2 (2012) ("October 2012 Order"), *order on reh'g and clarification*, 142 FERC ¶ 61,205 (2013) ("Integrated Marketplace Rehearing Order").

5 Submission of Tariff Revisions to Implement SPP Integrated Marketplace, Docket No. ER12-1179-003 (Feb. 15, 2013) ("February 2013 Compliance Filing").

6 Submission of Tariff Revisions to Modify SPP Integrated Marketplace, Docket No. ER13-1173-000 (Mar. 28, 2013) ("March 2013 Filing").

7 Compliance Filing of Southwest Power Pool, Inc., Docket No. ER12-1179-005 (Apr. 19, 2013) ("April 2013 Compliance Filing").

8 *Sw. Power Pool, Inc.*, 144 FERC ¶ 61,224, at P 20 (2013) ("September 2013 Order"), *reh'g pending*.

9 *Id.*

10 *Id.*

11 SPP Integrated Marketplace Compliance Filing, Docket No. ER12-1179-012 (dated Nov. 11, 2013) ("November 2013 Compliance Filing").

supplement SPP's Integrated Marketplace provisions and to address certain market computer system design issues.[12] On January 29, 2014, the Commission issued the January 2014 Order conditionally accepting the November 2013 Compliance Filing subject to an additional compliance filing within 30 days.[13] On the same day, the Commission issued a letter order conditionally accepting the November 2013 Supplemental Filing, subject to one additional revision.[14] SPP submitted a filing to comply with the January 2014 Letter Order on February 25, 2014.

II. DISCUSSION

The Tariff revisions and explanations submitted in this filing are designed to satisfy all compliance directives of the January 2014 Order. A more detailed description of these revisions is provided below, which is organized to track the discussion in the January 2014 Order.

A. Day-Ahead Market and Real-Time Balancing Market

1. Day-Ahead Must-Offer Requirement

In the January 2014 Order, the Commission conditionally accepted SPP's proposed revisions to its Day-Ahead must-offer requirement, finding that SPP's revisions clarify SPP's screening process for verification of the Day-Ahead must-offer requirement, including how the Market Monitor will use net resource capacity in the screening process.[15] The Commission found "that SPP has provided a more complete description of the range of firm purchases that may be included in determining a market participant's net resource capacity," but directed SPP to clarify in its Tariff how buyers and sellers in load transfer and/or bilateral contract arrangements will communicate arrangements with regard to must-offer obligations, and to explain further how these arrangements will be confirmed and how penalties for non-compliance will be assessed.[16]

SPP has adopted several Tariff revisions to comply with these directives. First, SPP has revised Section 2.2(11) of Attachment AE, which governs the Integrated

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12 Submission of Tariff Revisions to Modify SPP Integrated Marketplace, Docket No. ER14-416-000 (Nov. 15, 2013) ("November 2013 Supplemental Filing").

13 January 2014 Order at PP 1, 10.

14 *Sw. Power Pool, Inc.*, Letter Order, 146 FERC ¶ 61,049, Docket No. ER14-416-000 (Jan. 29, 2014) ("January 2014 Letter Order").

15 January 2014 Order at P 22.

16 *Id.* at P 23.

Marketplace registration process, to provide that, for purposes of the Day-Ahead must-offer requirement, "registration of the buyer's load by the seller shall be accounted for by including such load in the seller's Reported Load and not including such load in the buyer's Reported Load," and that "associated bilateral contracts shall not be included in either the buyer's or seller's net resource capacity."[17] SPP also revises Section 2.11.1(A)(1) of Attachment AE to clarify that when a seller registers a buyer's load, the buyer's Reported Load will be reduced by the amount of the buyer's load registered by the seller, and the seller's Reported Load will be increased by a corresponding amount.[18] Finally, to ensure that arrangements are properly verified and penalties properly assessed, SPP proposes to add clarifying revisions in Attachment AE Section 2.11.1(A)(4)(ii), which defines an entity's "net resource capacity" for purposes of the Day-Ahead must-offer requirement, to address how a load transfer will count in the calculation of net resource capacity and how the Market Monitor will verify firm power purchases and sales.[19] Together, these revisions clarify "how buyers and sellers in load transfer and/or bilateral contract arrangements will communicate arrangements with regard to must-offer obligations" and "explain how these arrangements will be confirmed and how penalties for non-compliance will be assessed."[20]

The Commission also determined that a Resource with a commitment status of "on an outage" (as specified in Attachment AE Section 4.1(10)(d)) "is not appropriate within Section 2.11.1.B(1)," and that a "market participant should not receive credit toward meeting its day-ahead must-offer obligation if it offered a resource that is on an approved outage and unavailable for commitment by SPP."[21] Accordingly, the Commission directed "SPP to remove from section 2.11.1.B(1) of Attachment AE the reference to section 4.1(10)(d) of Attachment AE."[22] In response to this directive, SPP has removed the reference to Section 4.1(10)(d) from Section 2.11.1(B)(1).[23] However, this revision requires an additional revision to be consistent with SPP's previously-accepted Day-Ahead must-offer requirement. Specifically, as originally proposed and as accepted by the October 18 Order, SPP's Day-Ahead must-offer requirement applies to

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17 *See* Revised Tariff, Attachment AE § 2.2(11).

18 *See id.*, Attachment AE § 2.11.1(A)(1).

19 *See id.*, Attachment AE § 2.11.1(A)(4)(ii).

20 January 2014 Order at P 23.

21 *Id.* at P 24.

22 *Id.*

23 *See* Revised Tariff, Attachment AE § 2.11.1(B)(1).

Resources to the extent they are available.[24] Section 2.11.1 as originally proposed and as revised in the February 2013 Compliance Filing contained such a limitation, and the limitation was replaced in the November 2013 Compliance Filing by the commitment statuses listed in Section 2.11.1(B)(1). In order both to preserve the import of SPP's previously-accepted Day-Ahead must-offer requirement and comply with the January 2014 Order, SPP proposes to reinstate language stating that Resources must be offered to the extent "available" in Section 2.11.1(B)(1) to make clear that Market Participants must offer "available" Resources and that a Market Participant obviously does not have to offer Resources that are not currently available.[25]

The Commission stated that "it is unclear why SPP has exempted resources with a commitment status pursuant to section 4.1(10)(c)[26] from being included in the day-ahead must-offer requirement," and thus directed SPP "to include this commitment status within sections 2.11.1.A(3) and 2.11.1.B(1) of Attachment AE or, in the alternative, explain why it is not appropriate to include this commitment status within day-ahead must-offer provisions."[27] SPP agrees with the Commission's finding that it is appropriate to include the emergency/local reliability only commitment status, and has revised Sections 2.11.1(A)(3) and 2.11.1(B)(1) accordingly.[28]

Finally, the Commission directed SPP either to: (1) provide a definition for "Net Resource Capacity" in the definitions section of Attachment AE; or (2) un-capitalize the term within section 2.11.1 of Attachment AE.[29] SPP has opted to un-capitalize the term, and has made corresponding revisions throughout Section 2.11.1 of Attachment AE.[30]

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24 *See, e.g.*, October 2012 Order at P 35 (describing SPP's Day-Ahead must-offer requirement being limited "to the extent that [a Market Participant's] resources are available").

25 *See* Revised Tariff, Attachment AE § 2.11.1(B)(1).

26 As the Commission noted, Section 4.1(10)(c) indicates that the Resource may be committed by SPP to alleviate an anticipated emergency condition or Local Reliability Issue. *See* January 2014 Order at P 25 n.33.

27 *Id.* at P 25.

28 *See* Revised Tariff, Attachment AE §§ 2.11.1(A)(3) & 2.11.1(B)(1).

29 January 2014 Order at P 26.

30 *See* Revised Tariff, Attachment AE §§ 2.11.1(A)(4), 2.11.1(B)(2), 2.11.1(C).

2. *Variable Energy Resources*

In the January 2014 Order, the Commission found that SPP complied with the requirement to provide an explanation of its methodology for determining its output forecasts for dispatchable VERs.[31] However, the Commission rejected SPP's proposed Tariff language in Sections 2.15(1) and 2.15(2) of Attachment AE that impose wind forecast data requirements "as specified in the Market Protocols."[32] The Commission instructed SPP to: (1) replace the phrase "as specified in the Market Protocols" with "as specified in the interconnection customer's interconnection agreement" in Section 2.15(1); and (2) remove "the Market Protocols and" from Section 2.15(2), so that it reads, in part, "as specified in the interconnection customer's interconnection agreement."[33] In response to these directives, SPP has modified Section 2.15 as specified.[34]

3. *Manual Commitment*

The Commission conditionally accepted SPP's proposed Tariff revisions to address the issue of manual commitments and associated cost allocation, finding that SPP generally complied with the compliance requirements of the September 2013 Order.[35] However, the Commission directed SPP to make additional revisions to its manual commitment and cost allocation processes, finding that "[t]he issue of manual commitments can be generally divided into four sub-issues: (1) the basis for manual commitments; (2) the parties that can make commitments; (3) the potential discriminatory impact of the manual commitments; and (4) the allocation of costs related to manual commitments."[36]

a. The Basis for Manual Commitments

The Commission determined that SPP's definition of "Local Reliability Issue" "is too narrow because it limits the definition to emergencies on facilities not modeled by SPP."[37] The Commission also determined that, while SPP attempted to "track" the Midcontinent Independent System Operator, Inc.'s ("MISO") Commission-approved

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31 January 2014 Order at P 35.

32 *Id.*

33 *Id.*

34 *See* Revised Tariff, Attachment AE §§ 2.15(1) & (2).

35 January 2014 Order at P 62.

36 *Id.* at P 63.

37 *Id.* at P 64.

definition of "Voltage and Local Reliability Commitment," there are significant differences between SPP's definition and the MISO definition, resulting in greater regional allocation of costs associated with manual commitments under the SPP definition than under the MISO definition.[38] Accordingly, the Commission directed SPP to adopt definitions of "Local Reliability Issue" and "Local Reliability Issue Commitment" as defined in the January 2014 Order.[39]

In response to this directive, SPP has adopted in Section 1.1 of Attachment AE (Definitions L) a definition of Local Reliability Issue Commitment that is identical to the definition provided in the January 2014 Order.[40] SPP also has modified the definition of Local Reliability Issue to match the definition provided in the January 2014 Order.[41]

The Commission also found "that SPP's proposed references to section 4.5.2(3)" to explain its process for selecting Resources for manual commitment "do not provide transparency to the manual commitment process," because "Section 4.5.2(3) explains how SPP will select long lead time resources on an economic basis."[42] On that basis, the Commission "directed SPP to remove all the references to section 4.5.2(3) from sections 5.2.2 and 6.1.2,"[43] but "to retain the remaining explanations of the process that SPP will utilize, as shown in the prescriptive changes in Appendix B."[44] SPP has made the required changes to Sections 5.2.2 and 6.1.2.[45]

b. The Parties that Can Make Manual Commitments

In the January 2014 Order, the Commission accepted SPP's definition of "Local Emergency Condition" as reasonable to limit the types of commitments that local transmission operators can make,[46] but directed SPP to "revise provisions in Attachment

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38 *Id.*

39 *Id.* at P 65 (providing definitions for "Local Reliability Issue" and "Local Reliability Issue Commitment").

40 *See* Revised Tariff, Attachment AE § 1.1 (Definitions L).

41 *See id.*

42 January 2014 Order at P 67.

43 *Id.*

44 *Id.* at P 67 n.85.

45 *See* Revised Tariff, Attachment AE §§ 5.2.2(3) & (4), 6.1.2(3) & (4).

46 January 2014 Order at P 68.

AE of the Tariff (e.g., section 5.2.2(4)) that limit the parties that can make manual commitments to address Local Reliability Issues."[47] The Commission also directed SPP "to revise section 5.2.2(4), which currently states that a manual commitment to address Local Reliability Issues may be made by the local transmission operator (or by SPP at the request of a local transmission operator) to state that SPP may make such commitments, too," consistent with the revisions in Appendix B of the January 2014 Order.[48] In response to these directives, SPP has revised Sections 5.2.2, 6.1.2, and 6.2.4 to limit the parties that may make manual commitments to address Local Reliability Issues and to state that SPP may manually commit Resources to address Local Reliability Issues as well.[49]

SPP notes that these changes necessitate one additional change not identified in Appendix B of the January 2014 Order. Specifically, Section 5.2.2(4), as currently drafted, states "[t]o the extent that the Transmission Provider, at the request of a local transmission operator, issues instructions to a Resource to address a Local Reliability Issue, such Resource shall be eligible for compensation in the same manner as any other Resource." With the revisions directed by the January 2014 Order, commitments to address Local Reliability Issues under this section will no longer be limited to those made by SPP "at the request of a local transmission operator." Accordingly, SPP proposes to remove "at the request of a local transmission operator" from this sentence.[50] This revision is consistent with other revisions directed by the January 2014 Order and depicted in Appendix B.

The Commission also found that, with the expansion of the definition of Local Reliability Issue and adoption of the Local Reliability Issue Commitment definition, Sections 5.2.2(5) and 6.1.2(5) of Attachment AE (which address SPP's manual commitment of Resources at a local transmission operator's request to address reliability issues other than Local Reliability Issues) may no longer be needed.[51] The Commission directed that SPP either justify the continued need for these provisions or delete them.[52] Similarly, the Commission noted that Section 6.2.4(5), which addresses circumstances in which a local transmission operator requests that SPP issue a manual dispatch instruction to resolve a reliability issue other than a Local Emergency Condition, also may no longer

47 *Id.* at P 69.

48 *Id.* at P 69 & n.87.

49 *See* Revised Tariff, Attachment AE §§ 5.2.2(4), 6.1.2(4), 6.2.4(5), 6.2.4(7).

50 *See id.*, Attachment AE § 5.2.2(4).

51 January 2014 Order at P 70.

52 *Id.*

be needed, and directed SPP to justify or remove this provision.[53] SPP agrees with the Commission that these provisions are no longer needed, and has thus deleted them and renumbered the subsequent subsections in each section as necessary.[54]

The Commission also observed that Section 5.2.2(6) of Attachment AE, which discusses the creation of operating guides for use in addressing known and recurring Local Reliability Issues in the Day-Ahead Reliability Unit Commitment ("RUC") process, must be modified to reflect SPP's ability to make commitments for Local Reliability Issues and to eliminate language suggesting that the local transmission operator may make such commitments.[55] SPP has made the changes directed by the Commission (as the Commission prescribed in Appendix B to the January 2014 Order).[56]

Finally, the Commission directed SPP to revise Section 8.6.7(A)(1) to clarify when a local transmission operator may direct a manual commitment, instructing SPP specifically to revise Section 8.6.7(A)(1) to state (addition in blackline): "Resources committed to address a Local Reliability Issue by the Transmission Provider at the request of a local transmission operator or committed by a local transmission operator to address a Local Emergency Condition . . . ." SPP has adopted the required change.[57]

c. Whether Manual Commitments Are Discriminatory

The Commission found that SPP complied with the Commission's directive to clarify that the Market Monitor will review manual commitments made both by SPP and

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53 *Id.* SPP notes that in two places in paragraph 70, the Commission refers to Section 6.2.4(6); however, SPP believes that the Commission intended to reference Section 6.2.4(5). Additionally, in footnote 89 of the January 2014 Order, the Commission states that "Sections 5.2.2(5), 6.1.2(5) and 6.2.4(6) are shown as deleted in the prescriptive changes in Appendix B." However, Section 6.2.4(5), not Section 6.2.4(6), is shown in Appendix B as deleted. SPP thus interprets paragraph 70 of the January 2014 Order to be referring to Section 6.2.4(5) (which contains provisions similar to those in Sections 5.2.2(5) and 6.1.2(5) relating to a local transmission operator's request for a commitment to address reliability issues other than Local Reliability Issues), rather than 6.2.4(6), and has revised the Tariff accordingly.

54 *See* Revised Tariff, Attachment AE §§ 5.2.2, 6.1.2, 6.2.4 (deleting subsection (5) in each section).

55 January 2014 Order at P 71.

56 *See* Revised Tariff, Attachment AE § 5.2.2(5) (previously Section 5.2.2(6)).

57 *See id.*, Attachment AE § 8.6.7(A)(1).

by the local transmission operator to ensure that such commitments were made in a non-discriminatory manner.[58] However, the Commission noted that SPP did not subject the Multi-Day Reliability Assessment analysis set forth in Section 4.5.3 of Attachment AE to the discrimination review, and therefore directed SPP to add to Sections 4.5.2(3) and 4.5.2(4) of Attachment AE language stating that "[s]uch manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under section 6.1.2.1 of this Attachment AE."[59] SPP has made the required changes to Sections 4.5.2(3) and (4).[60] The Commission also noted that, in a prior filing, SPP added language that would limit the applicability of the discrimination review to the RUC and the RTBM, and directed SPP to remove the words "in the Reliability Unit Commitment processes or Real-Time Balancing Market" from Section 6.1.2.1 of Attachment AE.[61] SPP has complied with this directive.[62]

The Commission observed that, while SPP included the criteria and factors to guide the Market Monitor's evaluation of whether a manual commitment by SPP or a local transmission operator was non-discriminatory, SPP did not include identical lists of factors as required by the September 2013 Order.[63] The Commission thus ordered SPP to adopt identical lists for the Market Monitor's review of both SPP commitments and local transmission operator commitments.[64] SPP has revised the list of factors that apply to SPP commitments to include "any affiliation with selected Resources"[65] and has modified the list of factors applicable to local transmission operator commitments to include "the cost."[66] With these changes, the lists are now identical.

The Commission also directed SPP to include more detail in the Tariff regarding the process for determining whether a manual commitment by a local transmission

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58 January 2014 Order at P 74.

59 *Id.*

60 *See* Revised Tariff, Attachment AE §§ 4.5.2(3) & (4).

61 January 2014 Order at P 74.

62 *See* Revised Tariff, Attachment AE § 6.1.2.1.

63 January 2014 Order at P 76.

64 *Id.*

65 *See* Revised Tariff, Attachment AE § 6.1.2.1(i).

66 *See id.*, Attachment AE § 6.1.2.1(ii).

operator is discriminatory.[67] Specifically, the Commission directed SPP to adopt specific Tariff revisions regarding manual commitments by local transmission operators to address "how the Market Monitor will obtain the necessary information, timeframes for making a determination and communicating its findings to market participants, and, if necessary, to the Commission's Office of Enforcement."[68] SPP has adopted several Tariff revisions to comply with this requirement.

First, to address the information requirements, SPP has added a new subsection 6.1.2.1(iii), which identifies how the Market Monitor will obtain the necessary information to perform the non-discrimination screen. The Market Monitor will obtain information to perform its non-discrimination verification from submitted Resource Offer parameters (cost, operating parameters, availability of non-selected Resources), Market Participant registration (Resource ownership, affiliation), and SPP and/or local transmission operator (prior commitments, other Resources considered to resolve the reliability issue or Local Emergency Condition).[69]

Second, to address the timing for the Market Monitor's review and communication to Market Participants, SPP has added language to new subsection 6.1.2.1(iii) to state that the Market Monitor's review will occur "as soon as the necessary information is available, but by no later than the day on which final Settlement Statements are issued for the Operating Day in which the manual commitment occurred, as set forth in Sections 8.0 and 10.1 of Attachment AE" of the Tariff.[70] Final Settlement Statements are issued 47 days after the Operating Day.[71]

Finally, to address reporting to the Commission's Office of Enforcement, SPP has revised existing Section 6.1.2.1(iii) of Attachment AE (which is renumbered to be Section 6.1.2.1(iv)), to state that the Market Monitor will report suspected discrimination to the Commission's Office of Enforcement "promptly upon completing the verification set forth in this Section 6.1.2.1."[72]

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67 January 2014 Order at P 78.

68 *Id.*

69 *See* Revised Tariff, Attachment AE § 6.1.2.1(iii).

70 *See id.*

71 *See* Tariff, Attachment AE §§ 8.0, 10.1.

72 *See* Revised Tariff, Attachment AE § 6.1.2.1(iv).

d. Allocation of Costs Related to Manual Commitments

The Commission determined that, with the revisions to the definition of Local Reliability Issue and the adoption of the term Local Reliability Issue Commitment, SPP's Tariff would appropriately allocate costs for manual commitments either regionally or locally based on the type of issue that the manual commitment was directed to address.[73] The Commission also determined that SPP's proposed definition of "Settlement Area" provides clarity and is just and reasonable, but directed SPP to make a change to its make whole payment provisions in Section 8.6.7(B) to ensure that make whole payments for manual commitments are allocated to the Settlement Area impacted by the Local Reliability Issue that gave rise to the make whole payment.[74] In response to this directive, SPP has revised Section 8.6.7(B)(1) to clarify that the RUC Local Settlement Area Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day for a Settlement Area for Resources committed by SPP or a local transmission operator to address Local Reliability Issues in the Settlement Area.[75]

e. Other Changes to the Manual Commitment Provisions

In addition to the changes noted above, the Commission directed SPP to make several additional revisions to Attachment AE Sections 5.2.2 (Day-Ahead RUC), 6.1.2 (Intra-Day RUC), and 6.2.4 (Out-of-Merit Energy Dispatch), as reflected in Appendix B of the January 2014 Order, to clarify payment responsibility and cost recovery for manual commitments.[76] SPP has made each of the changes identified in Appendix B, including revisions to Section 8.6.6 (Real-Time Out-of-Merit Amount).[77]

4. Marginal Losses

In the January 2014 Order, the Commission found that SPP's proposal for refunding marginal loss surpluses complies with Commission policy and the September 2013 Order because it provides a method for refunding surpluses that avoids making impermissible direct refunds.[78] The Commission also agreed with SPP's use of "Loss

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[73] January 2014 Order at P 80.

[74] *Id.* at P 81.

[75] *See* Revised Tariff, Attachment AE § 8.6.7(B)(1).

[76] January 2014 Order at P 82.

[77] *See generally* Revised Tariff, Attachment AE §§ 5.2.2, 6.1.2, 6.2.4, 8.6.6.

[78] January 2014 Order at P 90.

Pools" to allocate surpluses,[79] but directed SPP to revise the definition of "Loss Pool" to remove the phrase "Market Participant" because over-collected losses are allocated to Asset Owners rather than Market Participants.[80] SPP has made the ordered revision to the definition of Loss Pool in Section 1.1 (Definitions L) of Attachment AE.[81]

B. Market-Based Congestion Management

In the January 2014 Order, the Commission conditionally accepted SPP's proposed Tariff revisions regarding congestion management, finding that SPP complied with the September 2013 Order directive to allow transmission customers with rights to roll over their transmission service agreement to obtain ARRs in the annual allocation process without requiring them to give notice more than one year in advance.[82] However, the Commission found that "further clarification is needed to ensure that customers with rollover rights between March 15 and June 1 that elect to not exercise their rollover rights only receive ARRs until their contract expires."[83] Accordingly, the Commission directed SPP to modify Section 7.1.1 of Attachment AE "to provide that, for a customer with rollover rights between March 15 and June 1 that chooses not to exercise rollover rights, any ARRs associated with that contract will revert to SPP effective on the date the contract terminates."[84]

In response to this directive, SPP has revised Section 7.1.1 to state that SPP will assume that a contract with rollover rights that must be exercised between March 15 and June 1 will be renewed, "provided, however, that, if rollover rights for such Transmission Service are not exercised by the applicable deadline, any ARRs associated with such Transmission Service shall revert to the Transmission Provider effective on the date such Transmission Service terminates."[85]

C. Integration Issues – Bilateral Settlement Schedules

In the January 2014 Order, the Commission conditionally accepted SPP's proposed revisions to address Bilateral Settlement Schedules in the Integrated

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79 *Id.*

80 *Id.* at P 91.

81 *See* Revised Tariff, Attachment AE § 1.1 (Definitions L).

82 January 2014 Order at P 102.

83 *Id.*

84 *Id.*

85 *See* Revised Tariff, Attachment AE § 7.1.1.

Marketplace, subject to SPP making certain additional revisions. First, the Commission directed SPP to change the cut-off date for the "transition period" for preexisting bilateral agreements that the Commission directed SPP to adopt in previous orders,[86] to state that the cut-off will be "the start of the Integrated Marketplace" rather than "March 1, 2014."[87] SPP has made this change in Section 8.2.1 of Attachment AE.[88]

Second, the Commission found that SPP did not fully comply with the Commission's previous directive to modify Section 8.2 to be consistent with the default mechanism in Section 8.2.1 relating to preexisting bilateral agreements.[89] Specifically, the Commission directed SPP to revise Section 8.2 to read (revisions in blackline): "Either the buyer or the seller may terminate the Bilateral Settlement Schedule at any time <u>except when the Bilateral Settlement Schedule is associated with an existing bilateral agreement under section 8.2.1 of this Attachment AE</u>."[90] SPP has adopted this revision in Section 8.2 of Attachment AE.[91]

Third, the Commission found that SPP had not fully complied with the September 2013 Order directive to delete provisions that allow SPP unilaterally to terminate a Bilateral Settlement Schedule in the event that a party defaults.[92] The Commission reiterated its finding from the September 2013 Order that any defaults should be handled under the credit process set forth in Attachment X of the SPP Tariff.[93] The Commission thus directed SPP "to delete the language allowing it to unilaterally terminate a Bilateral Settlement Schedule in the event of default."[94] In accordance with this directive, SPP has deleted language indicating that SPP may terminate a Bilateral Settlement Schedule if

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86 *See* October 2012 Order at P 326 (directing SPP to establish a transition mechanism for preexisting bilateral agreements); September 2013 Order at P 222 (directing SPP to modify its Tariff to apply the transition mechanism for bilateral agreements that existed prior to the start of the Integrated Marketplace).

87 January 2014 Order at P 117.

88 *See* Revised Tariff, Attachment AE § 8.2.1.

89 January 2014 Order at P 118.

90 *Id.*

91 *See* Revised Tariff, Attachment AE § 8.2.

92 January 2014 Order at P 119.

93 *Id.*

94 *Id.*

either party is in default.[95] To provide clarity to the remaining language, SPP proposes to add language stating that Bilateral Settlement Schedules "will be administered" pursuant to Attachment X of the Tariff, and that "if a Bilateral Settlement Schedule is terminated pursuant to Attachment X," SPP will resettle with the Market Participants as if the Bilateral Settlement Schedule did not exist. These revisions are necessary to clarify that Bilateral Settlement Schedule defaults will be handled in accordance with Attachment X (as required by the September 2013 Order),[96] and to clarify how SPP will address any Bilateral Settlement Schedule terminations resulting from the processes set forth in Attachment X.

Finally, the Commission observed that Section 2.2(11) of Attachment AE, which governs load transfers under bilateral contracts, "is unclear as to what obligation the supplier is assuming regarding the 'provision of energy and capacity.'"[97] The Commission thus directed SPP to revise Section 2.2(11) to read (revisions in blackline): "For purposes of this section 2.2(11) of this Attachment AE, the sale of firm power shall refer to power sales deliverable with firm transmission service, with the supplier assuming the obligation <u>to serve the buyer's load with</u> ~~to provide~~ both capacity and energy."[98] SPP has adopted the changes required by the January 2014 Order.[99]

D. Market Monitoring and Mitigation

1. Parameters for Mitigation of Economic Withholding

The Commission found that Resources that are manually committed should be subject to tighter mitigation in Section 3.2 of Attachment AF, and agreed with the SPP Market Monitor that SPP's proposed Tariff revisions did not include all of the relevant references to Tariff provisions addressing manual commitment.[100] The Commission directed SPP to revise Section 3.1(3) of Attachment AF to add references to Attachment AE Sections 4.5.2 and 5.1.2 as requested by the Market Monitor, and also to add a reference to Section 4.5.3 of Attachment AE.[101] SPP has made these required changes,

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95 *See* Revised Tariff, Attachment AE § 8.2.

96 *See* September 2013 Order at P 225 ("[T]hat is, the Tariff's generally applicable default terms and conditions in Attachment X should apply.").

97 January 2014 Order at P 121.

98 *Id.*

99 *See* Revised Tariff, Attachment AE § 2.2(11).

100 January 2014 Order at P 132.

101 *Id.*

and has deleted language referring to the "Day-Ahead or Intra-Day RUC," as this language is no longer appropriate.[102] SPP also deletes from Section 3.1(3) of Attachment AF references to Sections 5.2.2(5) and 6.1.2(5) of Attachment AE, as these sections have been deleted as discussed in Section II.A.3.b above.[103]

2. Opportunity Costs to Be Included in Mitigated Offers

The Commission accepted SPP's proposed Tariff revisions to address Commission directives concerning the development of mitigated offers, subject to additional revisions.[104] First, the Commission directed SPP to reinsert "fuel supply limitations" in the list of legitimate and verifiable opportunity costs that can be included in a mitigated Energy Offer Curve, as set forth in Section 3.2(D) of Attachment AF of the Tariff.[105] In compliance with this requirement, SPP has reinserted "fuel supply limitations" as directed by the January 2014 Order.[106]

Second, the Commission directed SPP to revise the Tariff "to include language in section 3.2D specifying that run-time hour restrictions are to 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."[107] SPP has made this change in Section 3.2(D) of Attachment AF.[108]

Third, the Commission directed SPP to "provide that the price forecast model to be used in developing such opportunity costs will be determined by the Market Monitor, and that formulas and instructions will be published in the Market Protocols as part of the Mitigated Offer Development Guidelines, and updated as needed by the Market Monitor."[109] SPP adopts these changes in Section 3.2(D) of Attachment AF.[110]

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102 *See* Revised Tariff, Attachment AF § 3.1(3).

103 *See id.*, Attachment AF § 3.1(3); *see also* January 2014 Order at P 132 n.167.

104 January 2014 Order at P 170.

105 *Id.* at PP 170-71 & n.214.

106 *See* Revised Tariff, Attachment AF § 3.2(D).

107 January 2014 Order at P 172.

108 *See* Revised Tariff, Attachment AF § 3.2(D).

109 January 2014 Order at P 172.

110 *See* Revised Tariff, Attachment AF § 3.2(D).

Fourth, the Commission found that SPP "has not sufficiently addressed the opportunity costs that relate to operating reserves," and thus "require[d] SPP . . . to incorporate language into section 3.4 of Attachment AF providing that legitimate and verifiable opportunity costs may be included in the operating reserve offer, and that such opportunity costs will be evaluated by the Market Monitor, as is done for energy offers."[111] The Commission also required SPP to: (1) clarify that opportunity costs for operating reserves measured in forgone energy or other types of operating reserve production should not be included in mitigated offers; (2) address the price forecast for operating reserves in the determination of opportunity costs providing that any price forecast will be developed by the Market Monitor; and (3) revise Section 3.4 to provide that, with respect to inter-temporal opportunity costs for operating reserves, any run-time limitations that are applicable will be updated using the same processes established for Energy Offers set forth in Section 3.2(D) of Attachment AF.[112]

In response to these directives, SPP adopts a new subsection (F) in Section 3.4 of Attachment AF, stating:

> 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.[113]

These revisions comply with the Commission's directives in paragraphs 173 and 174 of the January 2014 Order addressing opportunity costs in mitigated Operating Reserve Offers.

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[111] January 2014 Order at P 173.

[112] *Id.* at P 174.

[113] *See* Revised Tariff, Attachment AF § 3.4(F).

Finally, the Commission directed SPP to correct a typographical error in Section 3.2(D),[114] which SPP has done.[115]

3. *Costs to Be Used in Mitigated Offer Development and Resolution of Conflicting Mitigated Offers*

In the January 2014 Order, the Commission found that "SPP has sufficiently explained how it will maintain consistency in the costs used in the development of mitigated offers by market participants, and how it will apply common factors consistently with respect to mitigated offers for energy, start-up, and no-load."[116] However, the Commission determined that SPP had not set forth in Section 3.4 of Attachment AF how it will apply common factors or measures (such as any related to fuel costs) to operating reserves.[117] Thus, the Commission directed SPP to submit Tariff revisions to "provide in section 3.4 of Attachment AF that for fuel costs and opportunity costs tied to fuel, market participants must provide the Market Monitor with an explanation of the market participant's fuel cost policy, and must indicate whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or spot market price."[118] SPP has complied with these directives by adopting a new subsection (G) in Attachment AF Section 3.4, which contains language similar to Commission-accepted language in Section 3.2 of Attachment AF governing submission and review of cost data for mitigated Energy Offers.[119]

The Commission also directed SPP to insert language into Section 3.5 of Attachment AF to specify that if the mitigated offer determined by the Market Participant and the Market Monitor differ, then the mitigated offer of the Market Monitor is to be used, unless the Market Participant disputes the level of the mitigated offer.[120] The Commission also required SPP to clarify that if the Market Participant formally disputes the level of the mitigated offer, then the previously accepted mitigated offer will be used

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114 January 2014 Order at P 175 (requiring SPP "to replace the term 'foregone' with the term 'forgone' in section 3.2D of Attachment AF").

115 *See* Revised Tariff, Attachment AF § 3.2(D).

116 January 2014 Order at P 187.

117 *Id.*

118 *Id.*

119 *See* Revised Tariff, Attachment AF § 3.4(G).

120 January 2014 Order at P 188.

from the time at which the formal dispute is made until it is resolved.[121] SPP has revised Section 3.5 of Attachment AF to provide these clarifications.[122]

The Commission did not accept SPP's proposal that if a mitigated offer dispute is resolved in favor of the Market Participant, SPP will recalculate market prices. The Commission found that this proposal "could lead to substantial disruption of the market," and, given the time involved in resolving such a dispute, would result in each revision to a mitigated offer in favor of a Market Participant being reported to the Commission for its approval.[123] The Commission thus required SPP to revise Section 3.5 to remove references to price corrections and market resettlements, and instead to adopt Tariff language requiring SPP to resolve mitigated offer disputes by providing make whole payments, as necessary, to Market Participants whose mitigated offer was improperly determined by the Market Monitor.[124] SPP has revised Section 3.5 of Attachment AF to provide make whole payments and has deleted references to market price corrections and resettlements in response to the Commission's directives.[125]

The Commission directed SPP to add to Sections 3.2 through 3.6 of Attachment AF language specifying that any cost data submitted under those sections (including additional opportunity cost data) will be subject to the confidentiality provisions contained in Section 11 of Attachment AE of the Tariff.[126] SPP has added language in each of the referenced sections to specify that the confidentiality provisions of Attachment AE Section 11 apply.[127]

4. Uneconomic Production

In the January 2014 Order, the Commission found that "[t]he application of the thresholds in section 3.6 of Attachment AF to uneconomic production is not straightforward," and that a Market Participant could engage in uneconomic production by lowering time-based or other offer parameters.[128] The Commission ordered SPP "to

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[121] *Id.*

[122] *See* Revised Tariff, Attachment AF § 3.5.

[123] January 2014 Order at P 189.

[124] *Id.* at P 190.

[125] *See* Revised Tariff, Attachment AF § 3.5.

[126] January 2014 Order at P 191.

[127] *See* Revised Tariff, Attachment AF §§ 3.2(F), 3.3(F), 3.4(H), 3.5, 3.6.

[128] January 2014 Order at P 194.

remove the reference in [Attachment AG] section 4.6.1.a(3) to section 3.6 of Attachment AF," and "[i]n its place . . . condition the reporting of time-based or other offer parameters to circumstances where it appears that uneconomic production is occurring or being facilitated by time-based or other (non-time and non-dollar) offer parameters."[129] In accordance with these directives, SPP has removed the reference in Attachment AG Section 4.6.1(a)(3) to Section 3.6 of Attachment AF, and replaced it with language specifying that potential uneconomic production will be indicated when "time-based or other (non-time and non-dollar) offer parameters contribute to congestion on transmission facilities or price separation between Reserve zones."[130]

The Commission also directed SPP to insert the word "Distribution" in the term "Resource-to-Load factor" in Section 4.6.1(a) of Attachment AG,[131] which SPP has done.[132]

5. Physical Withholding and Unavailability of Facilities

In the January 2014 Order, the Commission required SPP to remove from the end of Section 4.6.4.2(a) of Attachment AG the following phrase: "and has been determined to have contributed to the constraints, congestion or Local Reliability Issues as described in Section 4.6.4.2(a) of this Attachment AG."[133] SPP has made the required revision.[134]

6. Variable Energy Resources

In the January 2014 Order, the Commission found that SPP has satisfied the September 2013 Order directive to explain whether its monitoring and mitigation measures for economic withholding are appropriate for Non-Dispatchable Variable Energy Resources ("NDVER"), and agreed with SPP that mitigation of NDVERs for economic withholding of the Energy Offer curve under Attachment AF is unnecessary,

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129 *Id.* at P 195.

130 *See* Revised Tariff, Attachment AG § 4.6.1(a)(3).

131 January 2014 Order at P 195.

132 *See* Revised Tariff, Attachment AG § 4.6.1(a).

133 January 2014 Order at P 199. The January 2014 Order refers to Section 4.6.4(a), but the language that the Commission directed SPP to remove is contained in Section 4.6.4.2(a). SPP thus interprets paragraph 199 to mean that SPP should remove the quoted language from Section 4.6.4.2(a).

134 *See* Revised Tariff, Attachment AG § 4.6.4.2(a).

because such resources are unable to set prices.[135] Accordingly, the Commission directed SPP to revise Section 3.2 of Attachment AF of the Tariff to provide that the mitigation of economic withholding for Energy Offer curves will not be applied to NDVERs, but that monitoring will occur for Energy Offers of such resources.[136] In response, SPP has revised Section 3.2(D) of Attachment AF to state that "[m]itigation will not apply to Non-Dispatchable Variable Energy Resources in the Real-Time Balancing Market; monitoring for Energy Offers for Non-Dispatchable Variable Energy Resources will occur."[137]

The Commission also agreed with SPP that there should be monitoring and mitigation of all offer parameters of Dispatchable Variable Energy Resources ("DVER"), and conditionally accepted SPP's proposed language in Section 3.2(D) of Attachment AF that discusses the costs that may be included for DVERs, subject to SPP revising Section 3.2(D) to limit the applicability to DVERS, rather than to Variable Energy Resources generally.[138] SPP has complied by modifying Section 3.2(D) to refer to DVERs.[139]

7. Mitigation of Demand Response

In the January 2014 Order, the Commission conditionally accepted SPP's explanation of the mitigation and monitoring of Demand Response Resources, finding "that it is appropriate for the Market Monitor to review, on a case-by-case basis, the costs, including opportunity costs, to be included in the mitigated offer of a load reducing demand response resource."[140] However, the Commission directed SPP to provide further explanation of how it will determine forgone profits for inclusion in Demand Response Resource mitigated offers such that any such costs are consistently developed.[141]

As the Commission recognized,[142] the Market Monitor will review all proposed mitigated offers for load reducing Demand Response Resources on a case-by-case basis.

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135 January 2014 Order at P 207.

136 *Id.*

137 *See* Revised Tariff, Attachment AF § 3.2(D).

138 January 2014 Order at P 208.

139 *See* Revised Tariff, Attachment AF § 3.2(D).

140 January 2014 Order at P 217.

141 *Id.*

142 *Id.*

The Market Monitor will ensure that all costs are short-run marginal costs, excluding capital costs and going-forward costs. Short run marginal costs may include both explicit costs and opportunity costs. The explicit incremental costs are costs incurred by actually interrupting load for the hours when the Demand Response Resource is called upon. For example, such costs may include pre-chilling for interruptible air conditioning load. The opportunity costs are comprised of profits lost with the interruption of the production of a good, including any down-time required following the load curtailment. If the production of the good is subsequently made up through the use of additional Energy, the opportunity cost is only the difference, if any, in profit between the two time periods of production. Consistent with the expectations for other Resources, the Market Monitor will request adequate documentation to approximate the mitigated offer on a day-to-day basis and to ensure that costs are reflected accurately and consistently across Market Participants. Such documentation will include, at a minimum, historical revenues, variable costs, and hourly production for verification of the level of the hourly opportunity cost.

The Commission also found that SPP has not stated in the Tariff that Demand Response Resources will not be monitored for uneconomic production, noting that it appears that SPP had inserted such language into the wrong section of Attachment AG.[143] SPP agrees, and has moved language that was submitted in Section 4.6.3 of Attachment AG (Metric and Threshold Specifications) to Section 4.6.1.[144]

8. Monitoring and Mitigation of Virtual Bids and Offers

The Commission found that SPP's definition of "electrically similar locations" applicable to mitigation of virtual bids and offers would unnecessarily limit virtual bids and offers without sufficient justification.[145] Accordingly, the Commission directed SPP to remove language relating to "electrically similar Settlement Locations" from Section 4 of Attachment AF, which governs mitigation of virtual energy bids and virtual energy offers.[146] SPP has deleted the language identified by the Commission.[147]

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143 *Id.* at P 218. The Commission refers to Attachment AF; however, the monitoring provisions for uneconomic withholding are contained in Attachment AG.

144 *See* Revised Tariff, Attachment AG § 4.6.1.

145 January 2014 Order at P 221.

146 *Id.* at P 222.

147 *See* Revised Tariff, Attachment AF § 4.

E. Miscellaneous Compliance Issues

The Commission directed SPP to make one minor revision to Section 2.2(9) of Attachment AE, to move the placement of the words "or wholesale."[148] SPP has adopted the change directed by the January 2014 Order.[149]

III. EFFECTIVE DATE AND REQUEST FOR A WAIVER

SPP requests an effective date for the enclosed Tariff revisions of March 1, 2014, the effective date for SPP's previous Integrated Marketplace filings. To the extent necessary, SPP requests a waiver of the Commission's prior notice requirements in Section 35.3 of the Commission's regulations, 18 C.F.R. § 35.3. Good cause exists to grant a waiver because the waiver will enable the Tariff modifications required by the January 2014 Order to become effective on the same date as prior Integrated Marketplace Tariff language and compliance revisions, and SPP is submitting this filing in accordance with the 30-day timeline specified in the January 2014 Order.

IV. ADDITIONAL INFORMATION

A. Information Required by the Commission's Regulations

(1) Documents submitted with this filing:

In addition to this transmittal letter, SPP includes in this filing clean and redlined versions of the proposed Tariff revisions in electronic format.

(2) Effective date:

SPP requests that the Commission accept the proposed revisions to the SPP Tariff effective March 1, 2014, as discussed in more detail above.

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148 January 2014 Order at P 223.

149 *See* Revised Tariff, Attachment AE § 2.2(9).

(3) Service:

SPP has served a copy of this filing on all parties designated on the official service list compiled by the Secretary in this proceeding, as well as SPP's Members and Customers and all affected state commissions. A complete copy of this filing will be posted on the SPP web site, www.spp.org.

V. CONCLUSION

For all of the foregoing reasons, SPP respectfully requests that the Commission accept the Tariff revisions proposed in this filing as just and reasonable and in compliance with the January 2014 Order, effective as discussed above.

Respectfully submitted,

/s/ Barry S. Spector

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CERTIFICATE OF SERVICE

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

Dated at Washington, D.C., this 26th day of February, 2014.

/s/ Matthew J. Binette
Matthew J. Binette

Attorney for
Southwest Power Pool, Inc.

1.1 Definitions L

Local Emergency Condition

A condition or situation determined by the local transmission operator that is imminently likely to cause a material adverse effect on the security of or damage to the local transmission operator's facilities not modeled by the Transmission Provider.

Local Reliability Issue

A local voltage or reliability condition necessitating a Local Reliability Issue Commitment.

Local Reliability Issue Commitment

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

Locational Marginal Price ("LMP")

The price for Energy at a given Price Node which is equivalent to the marginal cost of serving demand at the Price Node while meeting the Transmission Provider Operating Reserve requirements.

Loss Pool

A collection of either (i) Settlement Locations within a Settlement Area (a "Settlement Area Loss Pool"), or (ii) all External Interfaces and Market Hubs located throughout the Transmission System, that is used for the purpose of determining an Asset Owner's allocation of over-collected loss revenues in Sections 8.5.16 or 8.6.16 of Attachment AE.

2.2 Application and Asset Registration

(1) Applications for a Market Participant to provide services in the Integrated Marketplace must be submitted to the Transmission Provider prior to the expected date of participation consistent with Section 6.4 of the Market Protocols. Applications must conform to the procedures specified in the Market Protocols and may be rejected if not complete. New Market Participants will follow the timeframe as specified in Section 6.4 of the Market Protocols in addition to the detailed model update timing requirements in Appendix E of the Market Protocols.

(2) As part of the application process, Market Participants must register all Resources and load, including applicable load associated with Grandfathered Agreements ("GFAs"), Non-Conforming Load and Demand Response Load with the Transmission Provider in accordance with the registration process specified in the Market Protocols. As part of Resource registration, Market Participants must specify whether settlement meter data will be submitted on a gross basis or net basis, where gross meter data does not include reductions for auxiliary load and net meter data is gross meter data reduced by auxiliary load. Both Non-Conforming Load and Demand Response Load may only be associated with a single Price Node except that Non-Conforming Load and Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes. Non-participating embedded load and/or generation must either: (i) register its load and/or generation in the Integrated Marketplace; or (ii) transfer its load and/or generation to an external Balancing Authority.

(3) Market Participants may elect to define a single Settlement Location that aggregates multiple Meter Data Submittal Locations associated with their load assets. Market Participants may not aggregate multiple Resource Meter Data Submittal Locations into a single Resource Settlement Location unless the Resources are at the same physical and electrically equivalent injection point to the Transmission System.

(4) In addition to the responsibilities described in Section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants wishing to model each participant's share of a Jointly Owned Unit as a separate Resource must choose one of the two options described below and provide the specified additional information. A Resource registered as a combined cycle Resource may not register as a Jointly Owned Unit.

(a) Individual Resource Option

Under the individual Resource option, each participant's share is modeled as a separate Resource for the purposes of commitment and dispatch and each Resource may be committed independent of the other Resource shares. In order to qualify for this option, each Market Participant must register its share and certify that it is greater than or equal to the minimum physical capacity operating limit of the physical Jointly Owned Unit.

The operating owner's Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit; and
- Maximum physical ten (10) minute response from an off-line state.

(b) Combined Resource Option

Under the combined Resource option each participant's share is modeled and must be registered as a separate Resource. Under this option, the commitment decision is made assuming that all Resource shares must be committed or none at all. Once committed, each share is dispatched independently. This option must be selected if the eligibility criteria stated under the individual Resource option cannot be met.

The operating owner's Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit;
- Maximum physical ten (10) minute response from an off-line state; and
- Participant share percentage by Market Participant.

(5) Market Participants may modify their registered assets in accordance with the asset registration procedures specified in the Market Protocols.

(6) All loads and all Resources, excluding Behind-The-Meter Generation less than 10 Megawatts ("MWs"), must register. Failure or refusal to register a Resource will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that Resource with the Commission under the name of the generation interconnection customer under an interconnection agreement with the Transmission Provider or the applicable Transmission Owner. In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility, such registration will not require the Qualifying Facility to participate in the Energy and Operating Reserve Markets or subject the Qualifying Facility to any charges or payments related to the Energy and Operating Reserve Markets. Any Energy and Operating Reserve Market charges or payments associated with the output of the Qualifying Facility will be allocated to the Market Participant representing the host utility purchasing the output of the Qualifying Facility under PURPA, and the Market Participant will be provided the settlement data required to verify the settlement charges and payments.

(7) A Market Participant wishing to Offer an External Resource in the Energy and Operating Reserve Markets will utilize an External Resource Pseudo-Tie in accordance with Attachment AO. In addition to the responsibilities outlined in Attachment AO, the Market Participant registering the External Resource will be responsible for registering and performing all responsibilities that are required of Resources in the Energy and Operating Reserve Markets.

(8) A Market Participant wishing to offer Demand Response Load as a Demand Response Resource in the Energy and Operating Reserve Markets must include in its application and registration a certification that participation in the Energy and Operating Reserve Markets by its Demand Response Resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Consistent with Section 2.8.1 of this Attachment, an aggregator of retail customers wishing to offer Demand Response Load in the form of a Demand Response Resource on behalf of one or more retail customers must also include in its application and registration a certification that participation of each retail customer is either: (1) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (2) affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year. Demand Response Resources must meet all application, registration and technical requirements applicable to the Energy and Operating Reserve Markets. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

(9) An aggregator of retail or wholesale customers offering Demand Response Load of one or more end-use retail customers or wholesale customers as a Demand

Response Resource in the Energy and Operating Reserve Markets must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants as well as certification consistent with Section 2.8 of this Attachment, as required.

(10) A wind-powered Variable Energy Resource with (1) an interconnection agreement executed after May 21, 2011 or (2) an interconnection agreement executed on or prior to May 21, 2011 and that commenced Commercial Operation on or after October 15, 2012 must register as a Dispatchable Variable Energy Resource. A wind-powered Variable Energy Resource with an interconnection agreement executed on or prior to May 21, 2011 may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Transmission Provider. Variable Energy Resources with fuel sources other than wind may optionally register as a Dispatchable Variable Energy Resource. Otherwise, Variable Energy Resources must register as Non-Dispatchable Variable Energy Resources. A Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may register as a Non-Dispatchable Variable Energy Resource or a Dispatchable Variable Energy Resource as described in the Market Protocols. Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resource.

(11) A Market Participant that is selling firm power to the load asset under a bilateral contract may, with the agreement of the buyer, register all or a portion of the buyer's load as its load asset. For purposes of this Section 2.2(11) of this Attachment AE, the sale of firm power shall refer to power sales deliverable with firm transmission service, with the supplier assuming the obligation to serve the buyer's load with both capacity and energy. For the purposes of Section 2.11.1 of this Attachment AE, such registration of the buyer's load by the seller shall be accounted for by including such load in the seller's Reported Load and not including such load in the buyer's Reported Load, as described under Section 2.11.1(A)(1) of this Attachment AE, and such associated bilateral contracts shall

not be included in either the buyer's or seller's net resource capacity described under Section 2.11.1(A)(4) of this Attachment AE.

(12) A Transmission Owner providing firm transmission service under a GFA eligible for GFA Carve Out must request removal of congestion and marginal loss charges and designate the GFA Responsible Entity within the timeframe set forth in Section 2.2 (1) of Attachment AE.

(13) A GFA Responsible Entity shall provide to the Transmission Provider the information necessary to administer the GFA Carve Out. The required information shall include the following:

(a) Resource Settlement Location;

(b) Load Settlement Location;

(c) The maximum MW capacity contracted under the GFA Carve Out;

(d) The identification of the GFA in Attachment W; and

(e) Any other information reasonably required by the Transmission Provider.

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.

(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, Regulation-Down and Contingency 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 or the Jointly Owned Unit combined Resource option as described under Section 2.2(4) 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) 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).

2.15 Provision of Wind Forecast Data

(1) Geographic data and wind turbine availability data for each wind-powered Variable Energy Resource must be submitted to the Transmission Provider as specified in the interconnection customer's interconnection agreement.

(2) An interconnection customer with a wind-powered Variable Energy Resource that executed an interconnection agreement on or after June 16, 2013 must submit, as specified in the interconnection customer's interconnection agreement in accordance with Attachment V: (i) site-specific meteorological data including temperature, wind speed, wind direction, relative humidity and atmospheric pressure and (ii) site specific geographic data including location (latitude and longitude) of the wind-powered Variable Energy Resource and location (latitude and longitude) and height of the facility that will contain the equipment necessary to provide the meteorological data for such resource. The Transmission Provider will accept such data from interconnection customers with other wind-powered Variable Energy Resources that executed an interconnection agreement prior to June 16, 2013 if provided by the interconnection customer.

4.5.2 Multi-Day Reliability Assessment Analysis

Using the inputs described above, the Transmission Provider will perform a capacity adequacy analysis for the upcoming Operating Day as follows:

(1) The Transmission Provider will calculate a Transmission Provider system requirement for each hour of the Operating Day as the sum of (a) Transmission Provider load forecast, (b) fixed Interchange Transaction Bids, (c) Regulation-Up requirement and (d) the Contingency Reserve requirement in each hour reduced by the wind Resource output forecast;

(2) The Transmission Provider will then calculate available Resource capacity in each hour as the sum of (a) Maximum Emergency Capacity Operating Limit for Resources other than long lead time Resources that are not on an approved Transmission Provider outage as submitted as part of the Resource Offer and (b) fixed Import Interchange Transaction Offers;

(3) For each hour of the Operating Day, the Transmission Provider will then compare the values calculated under (1) above and (2) above. If in any hour of the Operating Day, the values calculated under (1) above exceed the values calculated under (2) above, the Transmission Provider will commit available long lead time Resources on an economic basis to eliminate the deficiency as follows:

(a) For each available long lead time Resource, the Transmission Provider will calculate a commitment cost in dollars that is equal to:

(i) The sum of 1) the Resources Start-Up Offer, 2) the Resource's No-Load Offer multiplied by the greater of the Resource's Minimum Run Time (in hours) or the number of hours the Resource would be committed ignoring the Minimum Run Time, and 3) the Resources average cost to operate at Minimum Economic Capacity Operating Limit, as calculated from the Resource's Energy Offer Curve, multiplied by the greater of the Resource's Minimum Run Time (in hours) or the number of hours the Resource would be committed ignoring the Minimum Run Time.

(ii) The Transmission Provider will then create a merit order list starting with the least cost Resource based upon the commitment cost calculated in (i) above. The Transmission Provider will then select Resources for commitment in merit order until sufficient capacity is committed to relieve the anticipated capacity shortage with the objective of minimizing the total capacity committed to meet the anticipated shortage at the lowest overall commitment cost.

Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE.

(4) The Transmission Provider may also commit Resources to address Transmission System related reliability problems. Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE.

5.2.2 Day-Ahead Reliability Unit Commitment Execution

The Transmission Provider will perform a capacity adequacy analysis for the upcoming Operating Day using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider load forecast, Export Interchange Transactions, Head-room requirements, Floor-room requirements, and Operating Reserve requirements less Import Interchange Transactions over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers.

(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined in the submitted Energy Offer Curve.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, up to the Resources' Maximum Economic Capacity Operating Limit or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up, and down to the Resources' Minimum Economic Capacity Operating Limit or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down.

(a) If this capacity plus Import Interchange Transactions is not sufficient on a system-wide basis to meet the Transmission Provider load forecast, Export Interchange Transactions, Head-room requirements, and Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources' Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement.

(b) If there is a capacity surplus on a system-wide basis calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transactions, Floor-room requirements, and the Regulation-Down requirements that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transactions, the SCUC algorithm will, in priority order: (1) curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) incorporate capacity down to Resources' Minimum Emergency Capacity Operating Limits until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement; (3) de-commit Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is eliminated; and (4) de-commit self-committed Resources until the capacity surplus is eliminated.

(3) To the extent that a particular security constraint impacting only the Transmission System cannot be directly addressed within the SCUC algorithm and is not a Local Reliability Issue, the Transmission Provider may manually commit Resources and/or decommit Resources, including self-committed Resources to alleviate such a Transmission System security constraint in accordance with its authority as Reliability Coordinator. Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. Additionally, such manual commitments shall be selected by the Transmission Provider to ensure that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers. The recovery of the compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider regionally as described under Section 8.6.7(A) of this Attachment AE.

(4) A Local Reliability Issue may arise during the Day-Ahead Reliability Unit Commitment process. Such Local Reliability Issues may require out of merit commitment, decommitment, or dispatch instructions to be issued to one or more Resources to resolve the reliability issue. In such cases, the Transmission Provider shall issue or the local transmission operator shall request the Transmission Provider to issue such instructions and any commitment by the Transmission Provider shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. To the extent that the Transmission Provider issues instructions to a Resource to address a Local Reliability Issue, such Resource shall be eligible for compensation in the same manner as any other Resource. The recovery of the compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(5) The Transmission Provider, local transmission operator, and Resource owners shall develop operating guides to be applied to manual commitments made by the Transmission Provider, including such commitments made at the request of the local transmission operator to relieve known and recurring Local Reliability Issues in the Day-Ahead RUC. Such Resources will be compensated in the same manner as any other Resource. The recovery of such compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

6.1.2 Intra-Day Reliability Unit Commitment Execution

Using the inputs described in Section 6.1.1, the Transmission Provider will perform a capacity adequacy analysis using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider's load forecast, Export Interchange Transactions, Head-room requirements, Floor-room requirements, and Operating Reserve requirements less Import Interchange Transactions over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers.

(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined on the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the SCUC in making commitment decisions.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, only including capacity up to the Resources' Maximum Economic Capacity Operating Limits (or Maximum Regulation Capacity Operating Limits if selected for Regulation-Up) and down to the Resources' Minimum Economic Capacity Operating Limits (or Minimum Regulation Capacity Operating Limits if selected for Regulation-Down).

(a) If this capacity plus Import Interchange Transactions is not sufficient on a system-wide basis to meet the Transmission Provider's load forecast, Export Interchange Transactions, Head-room requirements, and Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources' Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement.

(b) If there is a system-wide capacity surplus calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transactions, Floor-room requirements, and the Regulation-Down requirements that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transaction, the Day-Ahead Market SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) Incorporate capacity down to Resources' Minimum Emergency Capacity Operating Limits until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement; (3) De-commit Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is eliminated; and (4) De-commit self-committed Resources until the capacity surplus is eliminated.

(3) To the extent that a particular reliability issue impacting only the Transmission System cannot be directly addressed within the SCUC algorithm and is not a Local Reliability Issue, the Transmission Provider may manually commit Resources and/or decommit Resources, including self-committed Resources to alleviate such Transmission System reliability issues. Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. The Transmission Provider shall ensure that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers. The recovery of the compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider regionally as described under Section 8.6.7(A) of this Attachment AE.

(4) A Local Reliability Issue may arise during the Intra-Day Reliability Unit Commitment Process. Such Local Reliability Issue may require out of merit commitment, decommitment, or dispatch instructions to be issued by the Transmission Provider to one or more Resources to resolve the Local Reliability Issue. Time permitting, the local transmission operator shall request the Transmission Provider to issue such instructions and any commitment by the Transmission Provider shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. To the extent that the Transmission Provider issues instructions to a Resource at the request of a local transmission operator to resolve a Local Reliability Issue, the Resource shall be eligible for compensation in the same manner as any other Resource. The recovery of the compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE. To the extent time does not permit, the local transmission operator may issue such instructions to the Resource if the Local Reliability Issue is a Local Emergency Condition. In such cases, the following shall take place:

(a) If initial instructions are issued by a local transmission operator, the transmission operator shall notify the Transmission Provider of the instructions given to the Resource.

(b) The transmission operator and Transmission Provider will coordinate to ensure subsequent instructions are provided by the Transmission Provider.

(c) The transmission operator shall log such instructions, and shall notify the Transmission Provider of such action. The Transmission Provider shall log such instructions as manual commitment, decommitment, or OOME Dispatch instruction, as appropriate, as if it gave such instruction to the Resource.

(d) The Resource shall be eligible to receive the compensation for such instructions in the same manner as if it had been committed by the

Transmission Provider; except that if the Market Monitor determines that the Resource selected in response to such instructions was selected in a discriminatory manner and the Resource was affiliated with the local transmission operator, such Resource shall not be eligible to receive compensation under Section 8.6.5 of this Attachment AE. Such determination shall be made by the Market Monitor using the standards and procedures set forth in Section 6.1.2.1 of this Attachment AE. Recovery of any compensation shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(e) The Transmission Provider, local transmission operator, and Resource owners shall develop operating guides to be applied to manual commitments made by the Transmission Provider including such commitments made at the request of the local transmission operator or manual commitments made by the local transmission operator during a Local Emergency Condition to relieve known and recurring Local Reliability Issues in the Intra-Day RUC. Such Resources will be compensated in the same manner as any other Resource. The recovery of the compensation paid by the Transmission Provider under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

6.1.2.1 Determination of Non-Discriminatory Manual Resource Selection

The Market Monitor shall verify that the process used by the Transmission Provider and local transmission operator to manually select Resources in response to a reliability issue was performed in a non-discriminatory manner. Such verification shall be performed as follows:

(i) The Market Monitor's evaluation of whether the Transmission Provider's selection process was non-discriminatory shall consider the cost, any affiliation with selected Resources, resource operating parameters, availability of non-selected Resources relative to the selected Resources and any prior instances where the Transmission Provider manually committed Resources to resolve the same reliability issue. The Transmission Provider's manual commitment of a Resource to resolve a reliability issue shall be considered non-discriminatory if the Resource selection was made without regard to ownership and the selected Resource effectively and economically mitigated the reliability issue, as verified by the Market Monitor.

(ii) The Market Monitor's evaluation of whether the local transmission operator's selection process was non-discriminatory shall consider the cost, any affiliation with selected Resources, resource operating parameters, availability of non-selected Resources relative to the selected Resources and any prior instances where the local transmission operator committed Resources to resolve the same Local Emergency Condition. The manual commitment of a Resource by a local transmission operator to resolve a Local Emergency Condition shall be considered non-discriminatory if the Resource selection was made without regard to ownership and the selected Resource effectively mitigated the Local Emergency Condition, as verified by the Market Monitor.

(iii) The Market Monitor shall obtain the necessary information to perform the verification from submitted Resource Offer parameters (cost, operating parameters, availability of non-selected Resources), Market Participant registration (Resource ownership, affiliation), and the Transmission Provider and/or local transmission operator (prior commitments, other Resources considered to resolve the reliability issue or Local Emergency Condition). The Market Monitor shall perform such verification as soon as the necessary information is available, but by no later than the day on which final Settlement Statements are issued for the Operating Day in which the manual commitment occurred, as set forth in Sections 8.0 and 10.1 of Attachment AE of this Tariff.

(iv) When the Market Monitor determines that a Resource may have been selected in a discriminatory manner pursuant to this Section 6.1.2.1, the

Market Monitor shall report such suspected discrimination to the Commission's Office of Enforcement or successor organization promptly upon completing the verification set forth in this Section 6.1.2.1, and the Transmission Provider shall notify the local transmission operator of the best practice should the situation arise again.

6.2.4 Out-of-Merit Energy Dispatch

The Transmission Provider may issue OOME dispatch directives to any on-line Resource to resolve Emergency Conditions or a reliability issue that the market systems cannot resolve. In addition, a local transmission operator may request the Transmission Provider to issue OOME dispatch directives to applicable on-line Resources to resolve a reliability issue or may issue OOME dispatch directives directly to resolve a Local Emergency Condition. Time permitting, OOME dispatch directives will be issued by the Transmission Provider. The Transmission Provider will make every effort to define and activate the appropriate constraints in RTBM SCED within one (1) hour of the manual reconfiguration. If initial instructions are issued by the local transmission operator, the local transmission operator shall coordinate with the Transmission Provider to ensure subsequent instructions are provided by the Transmission Provider.

When an OOME event occurs relating to a Local Emergency Condition, the local transmission operator may, when necessary, issue Manual Dispatch Instructions directly to the affected Resources and notify the Transmission Provider that it has done so and the Transmission Provider will take the following actions:

(1) Notifications are immediately issued that an OOME has been initiated and the Transmission Provider will issue Manual Dispatch Instructions at the MW level the Resource is expected to produce until such time as the constraint can be resolved by SCED through the RTBM.

(2) For the current dispatch interval and all future dispatch intervals not yet dispatched by the SCED, a Resource will receive Setpoint Instructions that are equal to the Manual Dispatch MW Instruction for the duration of OOME.

(3) The Transmission Provider will notify the Market Participant when the OOME event has ended.

(4) To the extent that the OOME was initiated directly by a local transmission operator to address a Local Emergency Condition, Market Participants shall be compensated for such OOME events in accordance with Section 8.6.6 of this Attachment AE as if they had been issued a Manual Dispatch Instruction by the Transmission Provider; except that if the Market Monitor determines that the Resource selected pursuant to Section 6.2.4(4) of this Attachment AE was

selected by the local transmission operator in a discriminatory manner and the Resource was affiliated with the local transmission operator, such Resource shall not be eligible for compensation under Section 8.6.6 of this Attachment AE. Such determination shall be made using the same standards and procedures prescribed for Resource selection in the Intra-Day Reliability Unit Commitment process, as set forth in Section 6.1.2.1 of this Attachment AE. The recovery of the compensation paid by the Transmission Provider shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(5) To the extent that the OOME was initiated by the Transmission Provider at the request of a local transmission operator to address a Local Reliability Issue, such Resources issued Manual Dispatch Instructions shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. In such event, Market Participants shall be compensated for such OOME events in accordance with Section 8.6.6 of this Attachment AE. The recovery of the compensation paid by the Transmission Provider shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(6) To the extent that the OOME was initiated by the Transmission Provider to address Emergency Conditions or a reliability issue that the market systems could not resolve, such Resources issued Manual Dispatch Instructions shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. Recovery of compensation for Resources directly issued Manual Dispatch Instructions by Transmission Provider that are received under Section 8.6.6 of this Attachment AE shall be collected regionally under Section 8.8 of this Attachment AE.

(7) The Transmission Provider, local transmission operator, and affected Resource owners shall develop operating guides to be applied to OOMEs made by the Transmission Provider including such commitments made at the request of the

local transmission operator to relieve known and recurring Local Reliability Issues or by the local transmission operator to relieve known and recurring Local Emergency Conditions. Such Resources will be compensated in the same manner as any other Resource that is issued OOME directives. The recovery of the compensation paid by the Transmission Provider under Section 8.6.6 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

In addition to the actions listed above, if a Manual Dispatch Instruction is issued in response to an Emergency Condition, the Transmission Provider will post the Emergency Condition on OASIS as soon as possible. The Transmission Provider shall displace the Manual Dispatch Instruction with a market solution as soon as possible consistent with system safety and reliability.

7.1.1 Transmission Service Verification

In order for Eligible Entities to obtain candidate ARRs, the Transmission Provider must first verify existing Transmission Service entitlements, including Transmission Service entitlements that have been renewed in accordance with rollover rights since their initial term. An Eligible Entity's Transmission Service must span the entire monthly or seasonal period for which ARRs are allocated to qualify for candidate ARRs in a particular month or season. For Transmission Service with rollover rights whose deadline for providing notice of rollover occurs after the annual ARR verification but before June 1, the Transmission Provider shall assume that the rollover will occur and shall consider the Transmission Service entitlement to span the entire allocation year, provided, however, that, if rollover rights for such Transmission Service are not exercised by the applicable deadline, any ARRs associated with such Transmission Service shall revert to the Transmission Provider effective on the date such Transmission Service terminates. The Transmission Provider will verify Eligible Entity existing Transmission Service entitlements as follows:

(1) The following will be performed prior to each annual ARR allocation for Eligible Entities taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service under the Tariff:

(a) The Transmission Provider will obtain source, sink and Reservation Capacity information from the OASIS for each monthly and seasonal period for which ARRs are allocated in which the Transmission Service spans the entire period, or would if or when rolled over, for the current annual allocation;

(i) For a Transmission Service reservation with a source inside the SPP Balancing Authority Area that is not a specific Resource or Resource Market Hub, the Transmission Provider will determine the load Settlement Location that most electrically corresponds to the source on the Transmission Service reservation that will be utilized as the source for candidate ARRs.

(ii) For a Transmission Service reservation with a source outside of the SPP Balancing Authority Area, the interface between the

Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the source for candidate ARRs.

(iii) For a Transmission Service reservation with a sink outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the sink for candidate ARRs.

(b) The Transmission Provider will provide this information to each Eligible Entity for verification; and

(c) Eligible Entities will notify the Transmission Provider within 2 weeks following receipt of this information, identifying and correcting inaccurate data on the OASIS. Otherwise, the Transmission Provider provided data will be considered verified.

(2) The following will be performed prior to each annual ARR allocation for the Eligible Entity taking GFA service:

(a) Each Transmission Owner shall register any GFA for which candidate ARRs are to be provided to the Transmission Owner or the transmission customer under the GFA on the Transmission Provider's OASIS. The Transmission Owner must provide the Transmission Provider with source, sink and Reservation Capacity information for each GFA on the Transmission Provider's OASIS by registering each GFA with the Transmission Provider. The Transmission Provider will use source, sink, and Reservation Capacity information from the GFA registration for each monthly and seasonal period for which ARRs are allocated. If both parties to the GFA are Market Participants with respect to the GFA load, then the parties may jointly inform the Transmission Provider which Market Participant will be allocated the candidate ARRs. If the parties to the GFA do not so inform the Transmission Provider, or if only the Transmission Owner that sold the GFA service is a Market Participant, then the

Transmission Owner that sold the GFA service will be allocated the candidate ARRs associated with the GFA.

(i) For a GFA with a source inside the SPP Balancing Authority Area that is not a specific Resource or Resource Market Hub, the Transmission Provider will determine the load Settlement Location that most electrically corresponds to the source on the Transmission Service reservation that will be utilized as the source for candidate ARRs.

(ii) For a GFA with a source outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the source for the candidate ARRs.

(iii) For a GFA with a sink outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the sink for the candidate ARRs.

(b) If the transmission customer under the GFA is receiving the candidate ARRs, to the extent that the transmission service specified in the GFA is identified as the equivalent of SPP Network Integration Transmission Service, the transmission customer under the GFA must provide the historical peak loads being served under the GFA for the previous three years.

8.2 Bilateral Settlement Schedules and GFA Carve Outs

Market Participants may create Bilateral Settlement Schedules for Energy and Operating Reserve obligations by registering and confirming the parameters of the agreement between buyer and seller as described in the Market Protocols. Both the buyer and seller must confirm the Bilateral Settlement Schedule except when the Bilateral Settlement Schedule is associated with an existing bilateral agreement under Section 8.2.1 of this Attachment AE. Either the buyer or seller may terminate the Bilateral Settlement Schedule at any time except when the Bilateral Settlement Schedule is associated with an existing bilateral agreement under Section 8.2.1 of this Attachment AE. In addition, Bilateral Settlement Schedules will be administered pursuant to Attachment X of this Tariff and, if a Bilateral Settlement Schedule is terminated pursuant to Attachment X, the Transmission Provider will resettle with Market Participants as if the Bilateral Settlement Schedule did not exist.

Market Participants may submit Bilateral Settlement Schedule quantities for Energy and Operating Reserve obligation for use in the Day-Ahead Market and may submit Bilateral Settlement Schedule quantities for Energy for use in the Real-Time Balancing Market up to four (4) days following the applicable Operating Day for the initial settlement. New submittals and revisions to previously submitted values may be submitted up to forty-four (44) days following the applicable Operating Day to be included in the final settlement. Submittals not confirmed by both parties will not be included in any settlement execution.

Transactions related to Bilateral Settlement Schedules for Energy must specify the Settlement Location, the MW amount, the buyer, the seller and which market it applies to (Day-Ahead Market or RTBM), and must be for the physical transfer of Energy, with title of the energy transferring from the seller to the buyer at the Settlement Location specified for the transaction. Market Participants that submit Bilateral Settlement Schedules for Energy shall use reasonable efforts to limit the megawatt hours of such transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract. The seller receives an increase in load obligation equal to the specified MW amount and the buyer receives a reduction in load obligation equal to the specified MW amount (the equivalent of a Resource settlement) at the specified Settlement Location.

Transactions related to Bilateral Settlement Schedules for Operating Reserve obligation must specify the buyer, the seller, the Operating Reserve product, the MW obligation transfer and the Reserve Zone within which the obligation transfer applies and must be for the physical transfer of energy associated with the Operating Reserve product, with title of the Operating Reserve product transferring from the seller to the buyer at the Reserve Zone specified for the transaction. The seller receives an increase in Operating Reserve obligation equal to the specified MW and the buyer receives a corresponding decrease in Operating Reserve obligation within the specified Reserve Zone.

8.2.1 Default Procedures for Pre-Existing Bilateral Contracts Transitioning to Integrated Marketplace

The procedures established under this Section 8.2.1 of Attachment AE shall apply to bilateral contracts entered into prior to the start of the Integrated Marketplace, where the buyer and seller have not agreed to the terms in the Bilateral Settlement Schedules corresponding to such pre-existing bilateral contracts:

(1) Upon request of the buyer, the Transmission Provider shall review and confirm that a particular bilateral contract exists between the buyer and seller. The Transmission Provider shall schedule a meeting between a designated senior representative of the buyer and seller within 30 days of such a request. The Transmission Provider shall conduct these discussions in accordance with Section 12 of the Tariff. Following confirmation, the buyer may register and confirm a Bilateral Settlement Schedule representing the parameters of the agreement. The Transmission Provider shall confirm that the buyer has submitted Bilateral Settlement Schedule parameters that are consistent with those specified in the bilateral contract;

(2) Subsequent submission by either the buyer or the seller of Bilateral Settlement Schedules for Energy and/or Operating Reserve associated with the registered Bilateral Settlement Schedule in either the Day-Ahead Market and/or RTBM must be consistent with the quantities specified in the bilateral contract. Only the buyer is required to confirm;

(3) Only the buyer may terminate the Bilateral Settlement Schedule;

(4) The Settlement Location for Bilateral Settlement Schedules for Energy shall be the source Settlement Location of the associated transmission service reservation as described under Section 7.1.1(1)(a) of this Attachment AE, as applicable;

(5) The Transmission Provider shall not be a party to Bilateral Settlement Schedules and nothing in this Section 8.2.1 of Attachment AE shall impose on the Transmission Provider any obligation regarding the settlement of financial rights and obligations between the parties to Bilateral Settlement Schedules; and

(6) Nothing in this Section 8.2.1 of Attachment AE shall alter the parties' rights and obligations under preexisting bilateral contracts, limit the right of either party to seek enforcement of such rights and obligations, and/or limit a party's right to obtain appropriate relief, pursuant to Section 206 of the FPA or as otherwise in accordance with the law.

8.6.6 Real-Time Out-of-Merit Amount

An RTBM OOME payment will be made to each Asset Owner with a Resource that receives a Transmission Provider Manual Dispatch Instruction that creates a cost to the Asset Owner or that adversely impacts the Asset Owner's Day-Ahead Market position for Energy and/or Operating Reserve. Resources issued a Manual Dispatch Instruction by a local transmission operator that the Market Monitor determines 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 are not eligible to receive a RTBM OOME payment. RTBM OOME payments made to Asset Owners that received a Manual Dispatch Instruction to address a Local Reliability Issue including Local Emergency Condition shall be recovered locally as described under Section 8.6.7(B). RTBM OOME payments made to Asset Owners that received a Manual Dispatch Instruction to address a reliability issue other than a Local Reliability Issue shall be recovered regionally under Section 8.8. The amount will be calculated on a Dispatch Interval basis as follows:

(1) If the Manual Dispatch Instruction is for Energy in the up direction and the Energy Offer Curve cost associated with the Resource's additional output attributable to its response ("OOME MW") is greater than the RTBM LMP, the Asset Owner will receive a payment for the difference multiplied by the OOME MW. The payment shall be limited to the amount necessary to compensate the Asset Owner for any under-recovery resulting from its Resource's response to the Manual Dispatch Instruction. The OOME MW is calculated as the positive difference between (i) the lesser of the actual Resource output or the Resource's Manual Dispatch Instruction MW and (ii) the Resource's economic operating point. The Resource's economic operating point is calculated as described under Section 8.6.5(4)(d);

(2) If the Manual Dispatch Instruction is for Energy in the down direction, including a Resource de-commitment and the RTBM LMP is greater than the Day-Ahead Market LMP, the Asset Owner will receive a payment equal to the difference multiplied by the Resource's reduction in output attributable to its response ("OOME MW"). The payment shall be limited to the amount necessary to

compensate the Asset Owner for any increase in net settlement costs resulting from its response to the Manual Dispatch Instruction. The OOME MW is calculated as the maximum of zero (0) or the difference between the Resource's Day-Ahead Market cleared Energy MW and the greater of (i) actual Resource output or (ii) the Resource's Manual Dispatch Instruction MW;

(3) If the Manual Dispatch Instruction or a Resource de-commitment instruction, causes the RTBM cleared amount of an Operating Reserve product to be less than the Day-Ahead Market cleared amount of the corresponding Operating Reserve product and the RTBM MCP is greater than the Day-Ahead Market MCP, the Asset Owner will receive a payment for the difference multiplied by the OOME Operating Reserve MW. The OOME Operating Reserve MW is calculated as the maximum of zero (0) or the difference between the Resource's Day-Ahead Market cleared Operating Reserve MW and the Resource's RTBM cleared Operating Reserve MW.

(4) To the extent that additional costs are incurred as a direct result of a Manual Dispatch Instruction that are not addressed through the compensation mechanisms described in (1) through (3) above, 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.

8.6.7 Reliability Unit Commitment Make Whole Payment Distribution Amount

An RTBM system-wide and local charge will be calculated at each Settlement Location for each Asset Owner for each hour in order to fund the payments made under Section 8.6.5. The system-wide amount will be determined by multiplying an Asset Owner's system-wide distribution volume by a daily system-wide RUC make whole payment rate as described in Section 8.6.7(A) of this Attachment AE. The local amount for each Settlement Area impacted by a Local Reliability Issue will be determined by multiplying an Asset Owner's local Settlement Area distribution volume by a daily local Settlement Area RUC make whole payment rate as described in Section 8.6.7(B) of this Attachment AE.

A. The RUC System-Wide Make Whole Payment Distribution Amount shall be calculated as follows:

The RUC System-Wide Make Whole Payment Distribution Amount =

[(RUC System-Wide Make Whole Payment Distribution Rate) *

(RUC System-Wide Make Whole Payment Distribution Volume)]

(1) The RUC System-Wide Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day as calculated under Section 8.6.5 excluding make whole payments made to Resources committed to address a Local Reliability Issue by the Transmission Provider at the request of a local transmission operator or committed by a local transmission operator to address a Local Emergency Condition, divided by the sum of Asset Owners' RUC System-Wide Make Whole Payment Distribution Volumes for all Settlement Locations for the entire Operating Day.

(2) An Asset Owner's RUC System-Wide Make Whole Payment Distribution Volume at a Settlement Location for an hour is equal to the sum of following values that are calculated for each Dispatch Interval within the hour:

(a) The absolute value of the sum of actual Real-Time Settlement Location deviations from Day-Ahead Market cleared amounts for load, virtual offer transactions and interchange transactions except that, during any Dispatch Interval in which the Transmission Provider has declared an Emergency Condition due to a capacity shortage, Real-Time actual load deviations from Day-Ahead Market cleared amounts shall be limited to deviations associated with actual Real-Time load in excess of amounts cleared in the Day-Ahead Market;

(b) For Resources cleared in the Day-Ahead Market, (a) the positive difference between the RTBM Resource applicable minimum limits and Day-Ahead Market Resource cleared Energy quantity; or (b) if the Resource has cleared regulation in the RTBM and has not cleared regulation in the Day-Ahead Market, the positive difference between (1) the RTBM Resource regulation minimum limit and (2) the greater of the Day-Ahead Market Resource cleared Energy quantity or the Resource's Day-Ahead Market regulation minimum limit, provided that:

(i) The applicable RTBM Resource minimum limit is greater than the comparable Day-Ahead Market Resource minimum limit by more than the Resource's Operating Tolerance; and

(ii) The applicable RTBM Resource minimum limit is greater than the Day-Ahead Market cleared Energy amount; and

(iii) The Resource received a Dispatch Instruction less than or equal to the RTBM applicable minimum limit for at least one Dispatch Interval in the hour.

(c) For Resources cleared in the Day-Ahead Market, (a) the positive difference between the Resource Day-Ahead Market cleared Energy quantity and the RTBM Resource applicable maximum limit or (b) if the Resource has cleared regulation in the RTBM and has not cleared regulation in the Day-Ahead Market, the positive difference between (1) the lesser of the Resource's RTBM regulation maximum limit or the Resource's Day-Ahead Market

Resource cleared Energy quantity and (2) the Resource's RTBM regulation maximum limit, provided that:

(i) The applicable RTBM Resource maximum limit is less than the comparable Resource maximum limit submitted for use in the Day-Ahead Market by more than the Resource's Operating Tolerance; and

(ii) The applicable RTBM Resource maximum limit is less than the Day-Ahead Market cleared Energy amount; and

(iii) The Resource received a Dispatch Instruction greater than or equal to the RTBM applicable maximum limit for at least one Dispatch Interval in the hour.

(d) For Resources cleared in the Day-Ahead Market, the Resource's Day-Ahead Market cleared amount if that Resource is off-line in the RTBM and if the Resource has not been de-committed by the Transmission Provider;

(e) For Resources that cleared in the Day-Ahead Market that are not able to follow Dispatch Instructions, the absolute value of the difference between a Resource's actual output and the Resource's economic operating point. The Resource's economic operating point is calculated as described under Section 8.6.5(4)(d);

(f) For Resources that were not offered in the Day-Ahead Market and that self-committed following the close of the Day-Ahead Market, and for Resources that were offered and not cleared in the Day-Ahead Market and that self-committed following the close of the Day-Ahead RUC, the actual Resource output if the Resource received a Dispatch Instruction less than or equal to the RTBM applicable minimum limit for at least one Dispatch Interval in the hour;

(g) A Resource's economic operating point, as calculated as described under Section 8.6.5(4)(d), for Resources that were committed following the close of the Day-Ahead Market if that Resource is off-line in the RTBM and that Resource was not de-committed by the Transmission Provider; and

(h) The absolute value of a Resource's URD if that Resource operated outside of its Operating Tolerance and the Resource has not been exempted from URD as described under Section 6.4.1.1 of this Attachment AE.

B. RUC Local Settlement Area Make Whole Payment Distribution Amount shall be calculated as follows:

RUC Local Settlement Area Make Whole Payment Distribution Amount =

[(RUC Local Settlement Area Make Whole Payment Distribution Rate) * (RUC Local Settlement Area Make Whole Payment Distribution Volume)]

(1) The RUC Local Settlement Area Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day for a Settlement Area as calculated under Sections 8.6.5 and 8.6.6 of this Attachment AE for Resources committed by the Transmission Provider at the request of a local transmission operator or by a local transmission operator to address a Local Reliability Issue in the Settlement Area, divided by the sum of Asset Owners' RUC Local Settlement Area Make Whole Payment Distribution Volumes within the impacted Settlement Area for the entire Operating Day.

(2) An Asset Owner's RUC Local Settlement Area Make Whole Payment Distribution Volume for the impacted Settlement Area for an hour is equal to that Asset Owner's Reported Load in that Settlement Area for that hour.

3. Mitigation Measures for Economic Withholding – Market Power in Energy and Operating Reserve

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 manually committed by the Transmission Provider or selected for commitment by a local transmission operator as described in Attachment AE, Sections 4.5.2, 4.5.3, 5.1.2, 5.2.2(3), 5.2.2(4), 6.1.2(3), and 6.1.2(4).

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 Areas shall be listed in Addendum 1 of this Attachment AF. Any new or modifications to existing Frequently Constrained Areas are subject to prior Commission approval.

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 or more frequently as the Market Monitor deems necessary. The Transmission Provider may propose an area be designated or undesignated as a Frequently Constrained Area if the Transmission Provider believes that conditions have changed with respect to the binding transmission constraint or binding Reserve Zone constraints that define the Frequently Constrained Area. The Market Monitor shall evaluate any proposed change and seek comments from the Market Participants before recommending to designate, modify, or undesignate a Frequently Constrained Area. Subject to any applicable confidentiality requirements, the Market Monitor will provide any interested Market Participants with a description of its supporting analysis to allow comment on the proposed designation changes. The Market Monitor will recommend any changes to the Frequently Constrained Areas to the SPP Board of Directors for approval.

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. The mitigated Energy Offer Curve may be updated up to 1100 hours on the day before the Operating Day 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 1100 hours on the day before the Operating Day will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day; 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.

A. The Energy Offer Curve conduct thresholds are as follows:

(1) For Resources with local market power as described in Section 3.1(4), the conduct threshold is a 10% increase above the mitigated Energy Offer Curve;

(2) For Resources located in a Frequently Constrained Area and not subject to Section 3.2(A)(1), the conduct threshold is a 17.5% increase above the mitigated Energy Offer Curve;

(3) For all other Resources the conduct threshold is a 25% increase above the mitigated Energy Offer Curve.

B. 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 Section 3.1; and

(3) The Resource either:

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

(b) Has local market power as described in Section 3.1(4).

An Energy Offer below $25/MWh will not be subject to mitigation measures for economic withholding.

C. The mitigated energy offer shall be the Resource's short-run marginal cost of producing energy as determined by the unit's heat rate; 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.

D. 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:

Mitigated Energy Offer ($/MWh) = HeatRate (mmBtu/MWh) * Performance Factor * Total Fuel Related Costs ($/mmBtu) + EOC VOM ($/MWh) + Opportunity Costs ($/MWh)

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.

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.

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 for Energy Offers for Non-Dispatchable Variable Energy Resources will occur.

E. 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. Intra-day changes to the mitigated energy offer curve must follow the mitigated offer development guidelines in the Market Protocols and will be validated by the Market Monitor.

F. In all cases under this Section 3.2, cost data submitted for the development of mitigated offers, including additional 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 1100 hours on the day before the Operating Day 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.

A. The Start-Up and No-Load Offer conduct thresholds are as follows:

(1) For Resources with local market power as described in Section 3.1(4), the conduct threshold is a 10% increase above the mitigated Start-Up or mitigated No-Load Offer, as applicable;

(2) For all other Resources the conduct threshold is a 25% increase above the mitigated Start-Up or mitigated No-Load Offer, as applicable.

B. 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 Section 3.1; and

(3) The Resource either:

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

(b) Has local market power as described in Section 3.1(4).

C. 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"), maintenance costs attributed to starts, and additional labor costs, if required above normal station staffing levels. The following formula shall apply to all mitigated Start-Up Offers:

Mitigated Start-Up Offer ($/Start) = [Start Fuel (mmBtu/Start) * Total Fuel Related Costs ($/mmBtu) * Performance Factor] + [Station Service (MWh/Start) *

Station Service Rate ($/MWh)] + Start VOM ($/Start) + Start Additional Labor Cost ($/Start)

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.

D. The mitigated No-Load Offer shall be the hourly fixed cost required to create a monotonically increasing mitigated Energy Offer Curve. It shall be calculated according to either of two methods:

(1) No-Load Fuel Approach

Mitigated No-Load Offer ($/hour) = No Load Fuel (mmBtu/hour) * Performance Factor * (No-Load VOM ($/mmBtu) + Total Fuel Related Cost ($/mmBtu)

(2) No-Load Cost Approach

Mitigated No-Load Offer ($/hour) =

(Heat Input at Minimum Economic Capacity Operating Limit (mmBtu) * Performance Factor *

(Total Fuel Related Cost ($/mmBtu) + No Load VOM ($/mmBtu))) –

(Incremental Cost up to Minimum Economic Capacity Operating Limit ($/MWh) * Minimum Economic Capacity Operating Limit (MW))

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.

E. 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. 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.

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

F. In all cases under this Section 3.3, cost data submitted for the development of mitigated offers, including additional opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this 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. The mitigated Operating Reserve Offers may be updated up to 1100 hours on the day before the Operating Day 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 1100 hours on the day before the Operating Day will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day; 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. The offer conduct thresholds for each of the Operating Reserve products are as follows:

    (1) For Resources with local market power as described in Section 3.1(4), the conduct threshold is a 10% increase above the mitigated offer for the applicable Operating Reserve Offer;

    (2) For all other Resources, the conduct threshold is a 25% increase above the mitigated offer for the applicable Operating Reserve Offer.

B. Any Operating Reserve Offer exceeding the applicable threshold, except offers below $10/MWh, will be deemed excessive. 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 Section 3.1; and

    (3) The Resource either:

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

        (b) Has local market power as described in Section 3.1(4).

C. 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:

Mitigated Spinning Reserve Offer ($/MW) ≤
(Additional Fuel Cost($/Hr) + Additional Maintenance Cost ($/Hr) + Condensing Power Cost ($/Hr)) /
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

D. The mitigated Regulation-Up 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:

Mitigated Regulation-Up Offer ($/MW) <
Cost Increase due to Heat Rate Increase during non-steady state operation ($/MW) +
Cost Increase in VOM ($/MW) + Uncompensated Cost ($/MW)

E. The mitigated Regulation-Down 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:

Mitigated Regulation-Down Offer ($/MW) <
Cost Increase due to Heat Rate Increase during non-steady state operation ($/MW) +

Cost Increase in VOM ($/MW) + Uncompensated Cost ($/MW)

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

F. 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.

G. 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.

H. In all cases under this Section 3.4, cost data submitted for the development of mitigated offers, including additional 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 in order to ensure that the Market Participant has correctly applied the formulas and definitions in Sections 3.2, 3.3, 3.4 and 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, the mitigated offer calculated by the Market Monitor shall be used. 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 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 threshold for Resources manually committed in accordance with Attachment AE, Sections 5.2.2(3), 6.1.2(3), and 6.1.2(4) of this Tariff: twenty-five percent (25%) increase.

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 additional 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 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. 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 impact test thresholds are as follows: At market start, the LMP impact threshold is five dollars ($5) per megawatt hour, the MCP impact threshold is five dollars ($5) per megawatt hour, and the make whole payment impact threshold is five dollars ($5) per megawatt hour. At the beginning of each six (6) month period after the market start, the LMP and MCP impact thresholds will be increased ten dollars ($10) per megawatt hour and the make whole payment impact threshold will be increased by ten dollars ($10) per megawatt hour unless the Market Monitor finds market behavior that warrants keeping the threshold constant for the next six (6) months. The periodic increases will continue until 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 relevant conduct threshold, as specified in Section 3.2, 3.3, or 3.4 of this Attachment AF.

B. If a Market Participant anticipates submitting an offer that will exceed the mitigated offer by more than the relevant conduct threshold, it may contact the Market Monitor to provide an explanation of the changes in its offer. If the Market Participant's pre-offer explanation indicates to the Market Monitor that the questioned behavior is consistent with competitive behavior, the Transmission Provider will not impose mitigation with respect to that offer unless and until circumstances are deemed to warrant it, and the Transmission Provider or the Market Monitor so notifies the

Market Participant. In circumstances where, following a Market Participant's pre-offer explanation, both the conduct and impact thresholds are violated but no mitigation is imposed, the Market Monitor will record such instances and will report such instances to the Commission's Office of Enforcement, or its successor organization, every three months during the first year of Integrated Marketplace operations, and yearly thereafter. To the extent that the report contains sensitive data, the Market Monitor should include any such data in a non-public version of the report.

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.

4. Mitigation Measures for Virtual Energy Bids and Virtual Energy Offers

If a determination is made, as specified in Section 4.6.3 of Attachment AG, that excessive divergence exists and the divergence is the result of the Virtual Energy Bids or Virtual Energy Offers of one or more Market Participants, the Transmission Provider shall impose mitigation measures. The mitigation measures will restrict the Market Participants that caused the divergence from submitting any Virtual Energy Bids or Virtual Energy Offers at the Settlement Locations where the Market Participant's Virtual Energy Bids or Virtual Energy Offers caused the excessive divergence. The mitigation measures shall be imposed for a period of three (3) months after which time the restriction will no longer apply.

4. Market Monitoring

4.1 Markets to be Monitored

The Market Monitor will monitor Markets and Services. The Market Monitor will not monitor bilateral energy, transmission or capacity markets and services not administered, coordinated or facilitated by SPP, except to assess the effect of these markets and services on Markets and Services, or the effects of Markets and Services on these unmonitored markets. Similarly, the Market Monitor will not monitor the energy, transmission or capacity markets and services in regions adjacent to the SPP Region except to assess the effect of these markets and services on Markets and Services, or the effects of Markets and Services on these adjacent markets.

4.2 Market Monitoring Scope

The Market Monitor will implement the Plan. The markets will require continuous monitoring by the Market Monitor. The Market Monitor will monitor Markets and Services by reviewing and analyzing market data and information including, but not limited to:

(a) Resource registration data;

(b) Resource Offer data including non-price related offer parameters required for use in either the Day-Ahead Market, Reliability Unit Commitment process and/or Real-Time Balancing Market;

(c) Demand Bids for the purchase of Energy in the Day-Ahead Market;

(d) Virtual Energy Bids for the purchase of Energy in the Day-Ahead Market and Virtual Energy Offers for the sale of Energy in the Day-Ahead Energy Market;

(e) Export Interchange Transaction Bids and Import Interchange Transaction Offers for the purchase and sale of Energy in the Day-Ahead Market and the Real-Time Balancing Market;

(f) Actual commitment and dispatch of Resources, including but not limited to Resource MW capability and output, MVAR capability and output, status, and outages;

(g) Locational Marginal Prices and zonal Market Clearing Prices at all Settlement Locations in or affecting any of Markets and Services;

(h) SPP Balancing Authority Area data, including but not limited to demand, area control error, Net Scheduled Interchange, actual total net interchange, and forecasts of operating reserves and peak demand;

(i) Conditions or events both inside and outside the SPP Balancing Authority Area affecting the supply and demand for, and the quantity and price of, products or services sold or to be sold in Markets and Services;

(j) Information regarding transmission services and rights, including the estimating and posting of Available Transfer Capability ("ATC") or Available Flowgate Capability ("AFC"), administration of this Tariff, the operation and maintenance of the transmission system, any auctions or other markets for transmission rights, and the reservation and scheduling of transmission service;

(k) Information regarding the nature and extent of transmission congestion in the region and, to the extent practicable, transmission congestion on any other system that affects Markets and Services, including but not limited to causes of, costs of and charges for transmission congestion, transmission facility loading, MVA capability, line status and outages;

(l) Settlement data for the Markets and Services;

(m) Any information regarding collusive or other anticompetitive or inefficient behavior in or affecting any of Markets and Services; and

(n) Generation resource operating cost data for estimating resource incremental cost, including fuel input costs, heat rates where applicable, start-up fuel requirements, environmental costs and variable operating and maintenance expenses.

(o) Logs of transmission service requests and Generation Interconnection Requests along with the disposition of each request and the explanation of any refused requests: and

(p) Any additional Resource and transmission facility outage data not otherwise provided for in this Section 4.2.

(q) GFA Carve Out Schedules.

4.2.1 Additional Market Monitor Duties

(a) In addition to the monitoring of market Data and Information, the Market Monitor may communicate with SPP Staff and Market Participants at any time for the purpose of monitoring and assessing market conditions.

(b) The Market Monitor shall evaluate the effectiveness of Markets and Services in signaling the need for investment in new generation, transmission or demand response infrastructure and report on its findings at least annually.

4.3 Referrals to the Commission

(a) The Market Monitor shall report suspected market violations, as defined in 18 CFR 35.28(b)(8), to FERC's Office of Enforcement (or its successor organization) staff in accordance with the FERC's reporting protocols for referrals by market monitors as specified in 18 C.F.R. § 35.28(g)(3)(iv) in a timely manner. Any such reports by the Market Monitor to FERC Staff shall be on a confidential basis, and all information and documents included in such reports will not be released to any other party except to the extent FERC directs or authorizes such release, unless such information and documents are already in the public domain.

4.4 Monitoring for Potential Integrated Marketplace Manipulation

The Market Monitor will monitor for potential instances of market manipulation in the Integrated Marketplace. Such actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices (including actions resulting in excessive day-ahead clearing prices), market conditions, or market rules for electric energy or electric products are prohibited. As listed by the FERC, prohibited behavior includes (a) wash trades, (b) submission of false data, (c) actions to cause artificial congestion and (d) collusive acts. The Market Monitor will report any market manipulation in the Integrated Marketplace in a timely manner.

4.5 Monitoring for Potential Transmission Market Power Activities

The Market Monitor shall monitor Markets and Services for the exercise of transmission market power by reviewing and analyzing data and information related to the availability of transmission facilities that impact access to services under this Tariff. The Market Monitor will monitor for activities particularly with respect to the withholding of transmission facilities or transmission capacity, including activities such as but not limited to, the following:

(a) Physical withholding by Transmission Owners by providing improper information related to the availability of transmission, such as information related to the capability or other modeling data used by SPP for use in system operations;

(b) Economic withholding by Transmission Owners through the use of methods and data for estimating costs of interconnection and system upgrades that is not comparable for affiliates and non-affiliates;

(c) Unavailability of transmission facilities through planned and unplanned maintenance outages that routinely exceed historical baselines; and

(d) Withholding of transmission capacity through excess reservations that are not actually used.

The Market Monitor shall refer any perceived market design flaws and recommended Tariff language changes to the Commission’s Office of Energy Market Regulation (or its successor office/organization). In addition, the Market Monitor shall refer any instance(s) of the suspected exercise of transmission market power directly to the Commission’s Office of Enforcement (or its successor organization) utilizing the protocols for referrals to the Commission for suspected instances of the exercise of market power that may be part of a suspected market violation, such as manipulation, in accordance with 18 C.F.R. § 35.28(g)(3)(iv). Where appropriate, the Market Monitor shall also provide the FERC with an estimate of damages equal to (i) the effect on prices multiplied by

(ii) the affected energy produced by the Transmission/Generation Owner. The Market Monitor may also request the FERC to impose additional sanctions and penalties, which may consist of a fixed dollar amount based on each instance, or an amount up to (i) the effect on prices multiplied by (ii) the affected energy produced by Market Participants other than the Transmission/Generation Owner. All such referrals by the Market Monitor to FERC will be on a confidential basis, and all information and documents included in such reports will not be released to any other party except to the extent FERC directs or authorizes such release.

4.6 Monitoring for Market Participant Behavior Possibly Warranting Mitigation

The Market Monitor shall monitor Markets and Services for potential abuse associated with the following categories of Market Participant behavior: (1) economic withholding; (2) uneconomic production; (3) physical withholding; (4) uneconomic Virtual Bids and Virtual Offers; and (5) gaming related to GFA Carve Out Schedules. The mitigation measures for each of the behaviors identified in items (1) through (4) of this paragraph are described in Attachment AF. When the Market Monitor determines that there is sufficient credible information about a specific abusive practice, the issue will be referred to the Commission's Office of Enforcement (or its successor organization). Nothing in this section shall limit the Market Monitor's obligation to refer other suspected market violations to the Commission's Office of Enforcement, even where suspected behavior does not fall explicitly within the abovementioned categories or descriptions.

4.6.1 Uneconomic Production

The Market Monitor will monitor for cases where uneconomic production by a Resource causes congestion on transmission facilities or price separation between Reserve Zones that is not justified by reliability concerns. The provisions of this Section 4.6.1 shall not apply to Demand Response Resources.

(a) Potential uneconomic production will be indicated, and subject to further analysis as described in (b) of this Section 4.6.1, when the Resource has a positive Resource-to-Load Distribution Factor and any of the following conditions are met:

(1) a Resource is identified with an incremental energy offer price less than 50 percent of the applicable reference level; or

(2) a Resource is determined to be generating outside of its Operating Tolerance; or

(3) time-based or other (non-time and non-dollar) offer parameters contribute to congestion on transmission facilities or price separation between Reserve Zones.

(b) For any Resource meeting the conditions described in (a) of this Section 4.6.1, the Market Monitor shall determine whether: (i) the MW impact from uneconomic production associated with such Resource is exacerbating the transmission congestion or binding a Reserve Zone; and (ii) the uneconomic production is not obviously justified by reliability or other operational concerns.

The Market Monitor will conduct evaluations as specified above and other related assessments to determine if there is sufficient credible information to justify referral to the Commission.

4.6.2 Monitoring for Virtual Energy Bids and Virtual Energy Offers

The Market Monitor will monitor the level of divergence between the Day-Ahead Market LMPs and the Real-Time Balancing Market LMPs. Section 4.6.3 defines the monitoring metric and thresholds to be used in determining the existence of excessive LMP divergence. In the case that there is excessive LMP divergence, the Market Monitor will determine if the LMP divergence is attributable to the Virtual Energy Bid and Virtual Energy Offer behavior of one or more Market Participants. If the Market

Monitor identifies one or more Market Participants as having caused the excessive LMP divergence through Virtual Energy Bid and Virtual Energy Offer behavior, then the Transmission Provider shall impose mitigation measures described in Section 4.0 of Attachment AF.

4.6.3 Metric and Threshold Specifications

The Market Monitor will compute the hourly LMP deviation between the Day-Ahead Market and Real-Time Balancing Market using the following formula: $[(LMP_{RTBM} / LMP_{DA\ Market}) – 1] * 100$. The average hourly LMP deviation is computed over a rolling four (4) week period or any other period that the Market Monitor determines is appropriate. If the four (4) week rolling average is below negative ten percent (-10%) or in excess of ten percent (10%), then the divergence is considered excessive and additional analysis is required.

4.6.4 Physical Withholding

The Market Monitor will monitor for physical withholding of capacity from the Energy and Operating Reserve Markets, and unavailability of facilities. Physical withholding and unavailability of facilities may include:

(a) Declaring that a Resource has been derated, forced out of service or otherwise been made unavailable for technical reasons that are untrue or that cannot be verified;

(b) Refusing to provide offers or schedules for a Resource when it would otherwise have been in the economic interest to do so without market power;

(c) Operating a Resource in real-time to produce an output level that is less than the dispatch instruction;

(d) Derating a transmission facility for technical reasons that are not true or verifiable;

(e) Operating a transmission facility in a manner that is not economic and that causes a binding transmission constraint or binding reserve zone or local reliability issue; and

(f) Declaring that the capability of Resources to provide Energy or Operating Reserves is reduced for reasons that are not true or verifiable.

Market Participants will not be deemed to be physically withholding if they are following the directions of the SPP Balancing Authority, Reliability Coordinator, or applicable reliability standards. In addition, Market Participants will not be determined to have physically withheld if they are selling into another market at a higher price.

4.6.4.1 Thresholds for Identifying Physical Withholding of Resource Capacity

4.6.4.1.1 A Market Participant is deemed to be physically withholding capacity in a Frequently Constrained Area if all of the following conditions exist:

(a) One or more of the transmission constraints or Reserve Zone constraints that define the Frequently Constrained Area are binding; and

(b) The Market Participant controls or owns a Resource located in the Frequently Constrained Area that satisfies condition 4.6.4(a), 4.6.4(b), 4.6.4(c), or 4.6.4(f) of this Attachment AG.

4.6.4.1.2 A Market Participant is deemed to be physically withholding capacity in an area not designated as a Frequently Constrained Area if all of the following conditions exist:

(a) One or more transmission constraints are binding or a Reserve Zone is binding; and

(b) The Resource(s) meets either of the following criteria (1) or (2);

(1) Such Resource(s) satisfy one of the conditions in Sections 4.6.4(a), 4.6.4(b), or 4.6.4(f) of this Attachment AG and the total withheld capacity exceeds the lower of 5 percent of the total capability owned or controlled by the Market Participant or 200 MW; or

(2) Where the real-time output of each such Resource is less than the Resource's Operating Tolerance defined in Attachment AE, Section 6.4.1 of this Tariff and the Resource is not exempt from Uninstructed Resource Deviation under Attachment AE, Section 6.4.1.1 of this Tariff.

4.6.4.2 Thresholds for Screening of Potential Physical Withholding of Transmission Facilities

A transmission facility fails the physical withholding screen if either of the following conditions is met:

(a) The transmission facility satisfies a condition in Section 4.6.4(d) or 4.6.4(e) of this Attachment AG; or

(b) The Market Monitor identifies a pattern of scheduling outages resulting in increased market costs compared to an alternative and lower cost impact outage schedule.

4.6.4.3 Sanctions

The Market Monitor will record instances where Market Participants have failed the screens in Sections 4.6.4.1 and 4.6.4.2 of this Attachment AG and notify the Commission's Office of Enforcement, or successor organization, of such behavior. In the event the Market Monitor determines there is credible evidence of a market violation, the Market Monitor shall make a referral to the Commission as described in Section 4.3 of this Attachment AG.

1.1 Definitions L

Local Emergency Condition

A condition or situation determined by the local transmission operator that is imminently likely to cause a material adverse effect on the security of or damage to the local transmission operator's facilities not modeled by the Transmission Provider.

Local Reliability Issue

A local voltage or reliability condition necessitating a Local Reliability Issue Commitment. ~~A Local Emergency Condition that requires either: (i) a Transmission Provider issued Resource commitment made at the request of the local transmission operator; or (ii) a local transmission operator issued Resource commitment. Such Resource commitment is issued in addition to commitments resulting from the Security Constrained Unit Commitment in the Day-Ahead Market or any Reliability Unit Commitment, in order to mitigate issues with local system voltage conditions or other Local Emergency Conditions. Transmission Provider Resource commitment requirements for a Local Reliability Issue are established prior to or during an Operating Day and are based on projected local reliability requirements developed in conjunction with local transmission operators, operational considerations, and generation and transmission outages. Transmission Provider and local transmission operator commitments for a Local Reliability Issue will be based on operating guides for recurring local system voltage conditions or other recurring Local Emergency Conditions, but an operating guide is not required prior to a resource commitment being designated as a voltage and local reliability commitment. Transmission Provider Resource commitments to relieve a potential or actual interconnection reliability operating limit violation will not be designated in this category.~~

Local Reliability Issue Commitment

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

Locational Marginal Price ("LMP")

The price for Energy at a given Price Node which is equivalent to the marginal cost of serving demand at the Price Node while meeting the Transmission Provider Operating Reserve requirements.

Loss Pool

A collection of either (i) Settlement Locations within a Settlement Area (a "Settlement Area Loss Pool"), or (ii) all External Interfaces and Market Hubs located throughout the Transmission System, that is used for the purpose of determining an ~~Market Participants~~ Asset Owner's allocation of over-collected loss revenues in Sections 8.5.16 or 8.6.16 of Attachment AE.

2.2 Application and Asset Registration

(1) Applications for a Market Participant to provide services in the Integrated Marketplace must be submitted to the Transmission Provider prior to the expected date of participation consistent with Section 6.4 of the Market Protocols. Applications must conform to the procedures specified in the Market Protocols and may be rejected if not complete. New Market Participants will follow the timeframe as specified in Section 6.4 of the Market Protocols in addition to the detailed model update timing requirements in Appendix E of the Market Protocols.

(2) As part of the application process, Market Participants must register all Resources and load, including applicable load associated with Grandfathered Agreements ("GFAs"), Non-Conforming Load and Demand Response Load with the Transmission Provider in accordance with the registration process specified in the Market Protocols. As part of Resource registration, Market Participants must specify whether settlement meter data will be submitted on a gross basis or net basis, where gross meter data does not include reductions for auxiliary load and net meter data is gross meter data reduced by auxiliary load. Both Non-Conforming Load and Demand Response Load may only be associated with a single Price Node except that Non-Conforming Load and Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes. Non-participating embedded load and/or generation must either: (i) register its load and/or generation in the Integrated Marketplace; or (ii) transfer its load and/or generation to an external Balancing Authority.

(3) Market Participants may elect to define a single Settlement Location that aggregates multiple Meter Data Submittal Locations associated with their load assets. Market Participants may not aggregate multiple Resource Meter Data Submittal Locations into a single Resource Settlement Location unless the Resources are at the same physical and electrically equivalent injection point to the Transmission System.

(4) In addition to the responsibilities described in Section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants wishing to model each participant's share of a Jointly Owned Unit as a separate Resource must choose one of the two options described below and provide the specified additional information. A Resource registered as a combined cycle Resource may not register as a Jointly Owned Unit.

(a) Individual Resource Option

Under the individual Resource option, each participant's share is modeled as a separate Resource for the purposes of commitment and dispatch and each Resource may be committed independent of the other Resource shares. In order to qualify for this option, each Market Participant must register its share and certify that it is greater than or equal to the minimum physical capacity operating limit of the physical Jointly Owned Unit.

The operating owner's Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit; and
- Maximum physical ten (10) minute response from an off-line state.

(b) Combined Resource Option

Under the combined Resource option each participant's share is modeled and must be registered as a separate Resource. Under this option, the commitment decision is made assuming that all Resource shares must be committed or none at all. Once committed, each share is dispatched independently. This option must be selected if the eligibility criteria stated under the individual Resource option cannot be met.

The operating owner's Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit;
- Jointly Owned Unit minimum physical capacity operating limit;
- Maximum physical ten (10) minute response from an off-line state; and
- Participant share percentage by Market Participant.

(5) Market Participants may modify their registered assets in accordance with the asset registration procedures specified in the Market Protocols.

(6) All loads and all Resources, excluding Behind-The-Meter Generation less than 10 Megawatts ("MWs"), must register. Failure or refusal to register a Resource will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that Resource with the Commission under the name of the generation interconnection customer under an interconnection agreement with the Transmission Provider or the applicable Transmission Owner. In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility, such registration will not require the Qualifying Facility to participate in the Energy and Operating Reserve Markets or subject the Qualifying Facility to any charges or payments related to the Energy and Operating Reserve Markets. Any Energy and Operating Reserve Market charges or payments associated with the output of the Qualifying Facility will be allocated to the Market Participant representing the host utility purchasing the output of the Qualifying Facility under PURPA, and the Market Participant will be provided the settlement data required to verify the settlement charges and payments.

(7) A Market Participant wishing to Offer an External Resource in the Energy and Operating Reserve Markets will utilize an External Resource Pseudo-Tie in accordance with Attachment AO. In addition to the responsibilities outlined in Attachment AO, the Market Participant registering the External Resource will be responsible for registering and performing all responsibilities that are required of Resources in the Energy and Operating Reserve Markets.

(8) A Market Participant wishing to offer Demand Response Load as a Demand Response Resource in the Energy and Operating Reserve Markets must include in its application and registration a certification that participation in the Energy and Operating Reserve Markets by its Demand Response Resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Consistent with Section 2.8.1 of this Attachment, an aggregator of retail customers wishing to offer Demand Response Load in the form of a Demand Response Resource on behalf of one or more retail customers must also include in its application and registration a certification that participation of each retail customer is either: (1) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (2) affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year. Demand Response Resources must meet all application, registration and technical requirements applicable to the Energy and Operating Reserve Markets. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

(9) An aggregator ~~or wholesale~~ of retail or wholesale customers offering Demand Response Load of one or more end-use retail customers or wholesale customers as

a Demand Response Resource in the Energy and Operating Reserve Markets must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants as well as certification consistent with Section 2.8 of this Attachment, as required.

(10) A wind-powered Variable Energy Resource with (1) an interconnection agreement executed after May 21, 2011 or (2) an interconnection agreement executed on or prior to May 21, 2011 and that commenced Commercial Operation on or after October 15, 2012 must register as a Dispatchable Variable Energy Resource. A wind-powered Variable Energy Resource with an interconnection agreement executed on or prior to May 21, 2011 may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Transmission Provider. Variable Energy Resources with fuel sources other than wind may optionally register as a Dispatchable Variable Energy Resource. Otherwise, Variable Energy Resources must register as Non-Dispatchable Variable Energy Resources. A Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may register as a Non-Dispatchable Variable Energy Resource or a Dispatchable Variable Energy Resource as described in the Market Protocols. Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resource.

(11) A Market Participant that is selling firm power to the load asset under a bilateral contract may, with the agreement of the buyer, register all or a portion of the buyer's load as its load asset. For purposes of this Section 2.2(11) of this Attachment AE, the sale of firm power shall refer to power sales deliverable with firm transmission service, with the supplier assuming the obligation to serve the buyer's load with ~~provide~~ both capacity and energy. For the purposes of Section 2.11.1 of this Attachment AE, such registration of the buyer's load by the seller shall be accounted for by including such load in the seller's Reported Load and not including such load in the buyer's Reported Load, as described under Section 2.11.1(A)(1) of this Attachment AE, and such associated bilateral contracts shall

not be included in either the buyer's or seller's net resource capacity described under Section 2.11.1(A)(4) of this Attachment AE.

(12) A Transmission Owner providing firm transmission service under a GFA eligible for GFA Carve Out must request removal of congestion and marginal loss charges and designate the GFA Responsible Entity within the timeframe set forth in Section 2.2 (1) of Attachment AE.

(13) A GFA Responsible Entity shall provide to the Transmission Provider the information necessary to administer the GFA Carve Out. The required information shall include the following:

(a) Resource Settlement Location;

(b) Load Settlement Location;

(c) The maximum MW capacity contracted under the GFA Carve Out;

(d) The identification of the GFA in Attachment W; and

(e) Any other information reasonably required by the Transmission Provider.

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~~, including load that is registered by a Market Participant under Section 2.2(11) of this Attachment AE~~. 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.

(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, Regulation-Down and Contingency 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, ~~or that~~ 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), ~~and~~ 4.1(10)(b), and 4.1(10)(c) of the Attachment AE.

(4) A Market Participant's ~~Net~~ net ~~Resource~~ resource ~~Capacity~~ 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 or the Jointly Owned Unit combined Resource option as described under Section 2.2(4) 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)(~~d~~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~~ net ~~Resource~~ resource ~~Capacity~~ 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) 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~~ net ~~Resource~~ resource ~~Capacity~~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).

2.15 Provision of Wind Forecast Data

(1) Geographic data and wind turbine availability data for each wind-powered Variable Energy Resource must be submitted to the Transmission Provider as specified in the interconnection customer's interconnection agreement~~Market Protocols~~.

(2) An interconnection customer with a wind-powered Variable Energy Resource that executed an interconnection agreement on or after June 16, 2013 must submit, as specified in ~~the Market Protocols and~~ the interconnection customer's interconnection agreement in accordance with Attachment V: (i) site-specific meteorological data including temperature, wind speed, wind direction, relative humidity and atmospheric pressure and (ii) site specific geographic data including location (latitude and longitude) of the wind-powered Variable Energy Resource and location (latitude and longitude) and height of the facility that will contain the equipment necessary to provide the meteorological data for such resource. The Transmission Provider will accept such data from interconnection customers with other wind-powered Variable Energy Resources that executed an interconnection agreement prior to June 16, 2013 if provided by the interconnection customer.

4.5.2 Multi-Day Reliability Assessment Analysis

Using the inputs described above, the Transmission Provider will perform a capacity adequacy analysis for the upcoming Operating Day as follows:

(1) The Transmission Provider will calculate a Transmission Provider system requirement for each hour of the Operating Day as the sum of (a) Transmission Provider load forecast, (b) fixed Interchange Transaction Bids, (c) Regulation-Up requirement and (d) the Contingency Reserve requirement in each hour reduced by the wind Resource output forecast;

(2) The Transmission Provider will then calculate available Resource capacity in each hour as the sum of (a) Maximum Emergency Capacity Operating Limit for Resources other than long lead time Resources that are not on an approved Transmission Provider outage as submitted as part of the Resource Offer and (b) fixed Import Interchange Transaction Offers;

(3) For each hour of the Operating Day, the Transmission Provider will then compare the values calculated under (1) above and (2) above. If in any hour of the Operating Day, the values calculated under (1) above exceed the values calculated under (2) above, the Transmission Provider will commit available long lead time Resources on an economic basis to eliminate the deficiency as follows:

(a) For each available long lead time Resource, the Transmission Provider will calculate a commitment cost in dollars that is equal to:

(i) The sum of 1) the Resources Start-Up Offer, 2) the Resource’s No-Load Offer multiplied by the greater of the Resource’s Minimum Run Time (in hours) or the number of hours the Resource would be committed ignoring the Minimum Run Time, and 3) the Resources average cost to operate at Minimum Economic Capacity Operating Limit, as calculated from the Resource’s Energy Offer Curve, multiplied by the greater of the Resource’s Minimum Run Time (in hours) or the number of hours the Resource would be committed ignoring the Minimum Run Time.

(ii) The Transmission Provider will then create a merit order list starting with the least cost Resource based upon the commitment cost calculated in (i) above. The Transmission Provider will then select Resources for commitment in merit order until sufficient capacity is committed to relieve the anticipated capacity shortage with the objective of minimizing the total capacity committed to meet the anticipated shortage at the lowest overall commitment cost.

Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE.

(4) The Transmission Provider may also commit Resources to address Transmission System related reliability problems. Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE.

5.2.2 Day-Ahead Reliability Unit Commitment Execution

The Transmission Provider will perform a capacity adequacy analysis for the upcoming Operating Day using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider load forecast, Export Interchange Transactions, Head-room requirements, Floor-room requirements, and Operating Reserve requirements less Import Interchange Transactions over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers.

(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined in the submitted Energy Offer Curve.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, up to the Resources' Maximum Economic Capacity Operating Limit or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up, and down to the Resources' Minimum Economic Capacity Operating Limit or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down.

(a) If this capacity plus Import Interchange Transactions is not sufficient on a system-wide basis to meet the Transmission Provider load forecast, Export Interchange Transactions, Head-room requirements, and Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources' Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement.

(b) If there is a capacity surplus on a system-wide basis calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transactions, Floor-room requirements, and the Regulation-Down requirements that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transactions, the SCUC algorithm will, in priority order: (1) curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) incorporate capacity down to Resources' Minimum Emergency Capacity Operating Limits until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement; (3) de-commit Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is eliminated; and (4) de-commit self-committed Resources until the capacity surplus is eliminated.

(3) To the extent that a particular security constraint impacting only the Transmission System cannot be directly addressed within the SCUC algorithm and is not a Local Reliability Issue, the Transmission Provider may manually commit Resources and/or decommit Resources, including self-committed Resources to alleviate such a Transmission System security constraint in accordance with its authority as Reliability Coordinator. Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. Additionally, such manual commitments shall be selected by the Transmission Provider ~~using the process described under Section 4.5.2(3) of this Attachment AE~~ to ensure that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers. The ~~R~~recovery of the compensation paid by the Transmission Provider for such committed Resources ~~received~~ under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider regionally as described under Section 8.6.7(A) of this Attachment AE.

(4) A Local Reliability Issue may arise during the Day-Ahead Reliability Unit Commitment process. Such Local Reliability Issues may require out of merit commitment, decommitment, or dispatch instructions to be issued to one or more Resources to resolve the reliability issue. In such cases, the Transmission Provider shall issue or the local transmission operator shall request the Transmission Provider to issue such instructions and any commitment by the Transmission Provider shall be ~~based on the process set forth in Section 4.5.2(3) of this Attachment AE. Such manual commitments shall be~~ selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. To the extent that the Transmission Provider~~, at the request of a local transmission operator,~~ issues instructions to a Resource to address a Local Reliability Issue, such Resource shall be eligible for compensation in the same manner as any other Resource. The ~~R~~recovery of the compensation paid by the Transmission Provider for such committed Resources ~~received~~ under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

~~(5) In the event that the Transmission Provider issues instructions to a Resource at the request of a local transmission operator to resolve a reliability issue other than a Local Reliability Issue during the Day-Ahead Reliability Unit Commitment process, any commitment by the Transmission Provider shall be based on the process set forth in Section 4.5.2(3) of this Attachment AE. Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. To the extent that the Transmission Provider, at the request of a local transmission operator, manually commits a Resource to address a reliability issue other than a Local Reliability Issue, such Resource shall be eligible for compensation in the same manner as any other Resource. Recovery of compensation for such committed Resources received under Section 8.6.5 of this Attachment AE shall be collected regionally as described under Section 8.6.7(A) of this Attachment AE.~~

(~~6~~5) The Transmission Provider, local transmission operator, and Resource owners shall develop operating guides to be applied to manual commitments made by the Transmission Provider, including such commitments made at the request of the local transmission operator ~~or by the local transmission operator~~ to relieve known and recurring Local Reliability Issues in the Day-Ahead RUC. Such Resources will be compensated in the same manner as any other Resource. The ~~R~~recovery of such compensation paid by the Transmission Provider for such committed Resources ~~received~~ under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

6.1.2 Intra-Day Reliability Unit Commitment Execution

Using the inputs described in Section 6.1.1, the Transmission Provider will perform a capacity adequacy analysis using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider's load forecast, Export Interchange Transactions, Head-room requirements, Floor-room requirements, and Operating Reserve requirements less Import Interchange Transactions over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers.

(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined on the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the SCUC in making commitment decisions.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, only including capacity up to the Resources' Maximum Economic Capacity Operating Limits (or Maximum Regulation Capacity Operating Limits if selected for Regulation-Up) and down to the Resources' Minimum Economic Capacity Operating Limits (or Minimum Regulation Capacity Operating Limits if selected for Regulation-Down).

(a) If this capacity plus Import Interchange Transactions is not sufficient on a system-wide basis to meet the Transmission Provider's load forecast, Export Interchange Transactions, Head-room requirements, and Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources' Maximum Emergency Capacity Operating Limits and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement.

(b) If there is a system-wide capacity surplus calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transactions, Floor-room requirements, and the Regulation-Down requirements that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transaction, the Day-Ahead Market SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) Incorporate capacity down to Resources' Minimum Emergency Capacity Operating Limits until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement; (3) De-commit Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is eliminated; and (4) De-commit self-committed Resources until the capacity surplus is eliminated.

(3) To the extent that a particular reliability issue impacting only the Transmission System cannot be directly addressed within the SCUC algorithm and is not a Local Reliability Issue, the Transmission Provider may manually commit Resources and/or decommit Resources, including self-committed Resources to alleviate such Transmission System reliability issues. Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE~~, using the process described under Section 4.5.2(3) of this Attachment AE to~~. The Transmission Provider shall ensure that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers. The ~~R~~recovery of the compensation paid by the Transmission Provider for such committed Resources ~~received~~ under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider regionally as described under Section 8.6.7(A) of this Attachment AE.

(4) A Local Reliability Issue may arise during the Intra-Day Reliability Unit Commitment Process. Such Local Reliability Issue may require out of merit commitment, decommitment, or dispatch instructions to be issued by the Transmission Provider to one or more Resources to resolve the Local Reliability Issue. Time permitting, the local transmission operator shall request the Transmission Provider to issue such instructions and any commitment by the Transmission Provider shall ~~be based on the process set forth in Section 4.5.2(3) of this Attachment AE. Such manual commitments shall~~ be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. To the extent that the Transmission Provider issues instructions to a Resource at the request of a local transmission operator to resolve a Local Reliability Issue, the Resource shall be eligible for compensation in the same manner as any other Resource. The ~~R~~recovery of the compensation paid by the Transmission Provider for such committed Resources ~~received~~ under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE. To the extent time does not permit, the local transmission operator may issue such instructions to the Resource if the Local Reliability Issue is a Local Emergency Condition. In such cases, the following shall take place:

(a) If initial instructions are issued by a local transmission operator, the transmission operator shall notify the Transmission Provider of the instructions given to the Resource.

(b) The transmission operator and Transmission Provider will coordinate to ensure subsequent instructions are provided by the Transmission Provider.

(c) The transmission operator shall log such instructions, and shall notify the Transmission Provider of such action. The Transmission Provider shall log such instructions as manual commitment, decommitment, or OOME Dispatch instruction, as appropriate, as if it gave such instruction to the Resource.

(d) The Resource shall be eligible to receive the compensation for such instructions in the same manner as if it had been committed by the Transmission Provider; except that if the Market Monitor determines that the Resource selected in response to such instructions was selected in a discriminatory manner and the Resource was affiliated with the local transmission operator, such Resource shall not be eligible to receive compensation under Section 8.6.5 of this Attachment AE. Such determination shall be made by the Market Monitor using the standards and procedures set forth in Section 6.1.2.1 of this Attachment AE. Recovery of any compensation shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(e) The Transmission Provider, local transmission operator, and Resource owners shall develop operating guides to be applied to manual commitments made by the Transmission Provider including such commitments made at the request of the local transmission operator or manual commitments made by the local transmission operator during a Local Emergency Condition to relieve known and recurring Local Reliability Issues in the Intra-Day RUC. Such Resources will be compensated in the same manner as any other Resource. The ~~R~~recovery of ~~such~~ the compensation paid by the Transmission Provider~~received~~ under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

~~(5) In the event that the Transmission Provider issues instructions to a Resource at the request of a local transmission operator to resolve a reliability issue other than a Local Reliability Issue during the Intra-Day Reliability Unit Commitment process, any commitment by the Transmission Provider shall be based on the process set forth in Section 4.5.2(3) of this Attachment AE. Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the~~

~~process described under Section 6.1.2.1 of this Attachment AE. To the extent that the Transmission Provider, at the request of a local transmission operator, manually commits a Resource to address a reliability issue other than a Local Reliability Issue, such Resource shall be eligible for compensation in the same manner as any other Resource. Recovery of compensation for such committed Resources received under Section 8.6.5 of this Attachment AE shall be collected regionally as described under Section 8.6.7(A) of this Attachment AE.~~

6.1.2.1 Determination of Non-Discriminatory Manual Resource Selection

The Market Monitor shall verify that the process used by the Transmission Provider and local transmission operator to manually select Resources ~~in the Reliability Unit Commitment processes or Real-Time Balancing Market~~ in response to a reliability issue was performed in a non-discriminatory manner. Such verification shall be performed as follows:

(i) The Market Monitor's evaluation of whether the Transmission Provider's selection process was non-discriminatory shall consider the cost, any affiliation with selected Resources, resource operating parameters, availability of non-selected Resources relative to the selected Resources and any prior instances where the Transmission Provider manually committed Resources to resolve the same reliability issue. The Transmission Provider's manual commitment of a Resource to resolve a reliability issue shall be considered non-discriminatory if the Resource selection was made without regard to ownership and the selected Resource effectively and economically mitigated the reliability issue, as verified by the Market Monitor.

(ii) The Market Monitor's evaluation of whether the local transmission operator's selection process was non-discriminatory shall consider the cost, any affiliation with selected Resources, resource operating parameters, availability of non-selected Resources relative to the selected Resources and any prior instances where the local transmission operator committed Resources to resolve the same Local Emergency Condition.

The manual commitment of a Resource by a local transmission operator to resolve a Local Emergency Condition shall be considered non-discriminatory if the Resource selection was made without regard to ownership and the selected Resource effectively mitigated the Local Emergency Condition, as verified by the Market Monitor.

(iii) The Market Monitor shall obtain the necessary information to perform the verification from submitted Resource Offer parameters (cost, operating parameters, availability of non-selected Resources), Market Participant registration (Resource ownership, affiliation), and the Transmission Provider and/or local transmission operator (prior commitments, other Resources considered to resolve the reliability issue or Local Emergency Condition). The Market Monitor shall perform such verification as soon as the necessary information is available, but by no later than the day on which final Settlement Statements are issued for the Operating Day in which the manual commitment occurred, as set forth in Sections 8.0 and 10.1 of Attachment AE of this Tariff.

(~~iii~~iv) When the Market Monitor determines that a Resource may have been selected in a discriminatory manner pursuant to this Section 6.1.2.1, the Market Monitor shall report such suspected discrimination to the Commission's Office of Enforcement or successor organization promptly upon completing the verification set forth in this Section 6.1.2.1, and the Transmission Provider shall notify the local transmission operator of the best practice should the situation arise again.

6.2.4 Out-of-Merit Energy Dispatch

The Transmission Provider may issue OOME dispatch directives to any on-line Resource to resolve Emergency Conditions or a reliability issue that the market systems cannot resolve. In addition, a local transmission operator may request the Transmission Provider to issue OOME dispatch directives to applicable on-line Resources to resolve a reliability issue or may issue OOME dispatch directives directly to resolve a Local Emergency Condition. Time permitting, OOME dispatch directives will be issued by the Transmission Provider. The Transmission Provider will make every effort to define and activate the appropriate constraints in RTBM SCED within one (1) hour of the manual reconfiguration. If initial instructions are issued by the local transmission operator, the local transmission operator shall coordinate with the Transmission Provider to ensure subsequent instructions are provided by the Transmission Provider.

When an OOME event occurs relating to a Local Emergency Condition, the local transmission operator may, when necessary, issue Manual Dispatch Instructions directly to the affected Resources and notify the Transmission Provider that it has done so and the Transmission Provider will take the following actions:

(1) Notifications are immediately issued that an OOME has been initiated and the Transmission Provider will issue Manual Dispatch Instructions at the MW level the Resource is expected to produce until such time as the constraint can be resolved by SCED through the RTBM.

(2) For the current dispatch interval and all future dispatch intervals not yet dispatched by the SCED, a Resource will receive Setpoint Instructions that are equal to the Manual Dispatch MW Instruction for the duration of OOME.

(3) The Transmission Provider will notify the Market Participant when the OOME event has ended.

(4) To the extent that the OOME was initiated directly by a local transmission operator to address a Local Emergency Condition, Market Participants shall be compensated for such OOME events in accordance with Section 8.6.6 of this Attachment AE as if they had been issued a Manual Dispatch Instruction by the Transmission Provider; except that if the Market Monitor determines that the Resource selected pursuant to Section 6.2.4(4) of this Attachment AE was

selected by the local transmission operator in a discriminatory manner and the Resource was affiliated with the local transmission operator, such Resource shall not be eligible for compensation under Section 8.6.6 of this Attachment AE. Such determination shall be made using the same standards and procedures prescribed for Resource selection in the Intra-Day Reliability Unit Commitment process, as set forth in Section 6.1.2.1 of this Attachment AE. The ~~R~~recovery of ~~any~~ the compensation paid by the Transmission Provider shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

~~(5) To the extent that the OOME was initiated by the Transmission Provider at the request of a local transmission operator to address a reliability issue other than a Local Emergency Condition, such Resources issued Manual Dispatch Instructions shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. In such event, Market Participants shall be compensated for OOME events in accordance with Section 8.6.6 of this Attachment AE. Recovery of such compensation shall be collected regionally as described under Section 8.6.7(A) of this Attachment AE.~~

(~~6~~5) To the extent that the OOME was initiated by the Transmission Provider at the request of a local transmission operator to address a Local Reliability Issue~~Emergency Condition~~, such Resources issued Manual Dispatch Instructions shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. In such event, Market Participants shall be compensated for such OOME events in accordance with Section 8.6.6 of this Attachment AE. The ~~R~~recovery of ~~such~~ the compensation paid by the Transmission Provider shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(~~7~~6) To the extent that the OOME was initiated by the Transmission Provider to address Emergency Conditions or a reliability issue that the market systems could not resolve, such Resources issued Manual Dispatch Instructions shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. Recovery of compensation for Resources directly issued Manual Dispatch Instructions by Transmission Provider that are received under Section 8.6.6 of this Attachment AE shall be collected regionally under Section 8.8 of this Attachment AE.

(~~8~~7) The Transmission Provider, local transmission operator, and affected Resource owners shall develop operating guides to be applied to OOMEs made by the Transmission Provider including such commitments made at the request of the local transmission operator to relieve known and recurring Local Reliability Issues or by the local transmission operator to relieve known and recurring Local Emergency Conditions. Such Resources will be compensated in the same manner as any other Resource that is issued OOME directives. The ~~R~~recovery of ~~such~~ the compensation paid by the Transmission Provider ~~received~~ under Section 8.6.6 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

In addition to the actions listed above, if a Manual Dispatch Instruction is issued in response to an Emergency Condition, the Transmission Provider will post the Emergency Condition on OASIS as soon as possible. The Transmission Provider shall displace the Manual Dispatch Instruction with a market solution as soon as possible consistent with system safety and reliability.

7.1.1 Transmission Service Verification

In order for Eligible Entities to obtain candidate ARRs, the Transmission Provider must first verify existing Transmission Service entitlements, including Transmission Service entitlements that have been renewed in accordance with rollover rights since their initial term. An Eligible Entity's Transmission Service must span the entire monthly or seasonal period for which ARRs are allocated to qualify for candidate ARRs in a particular month or season. For Transmission Service with rollover rights whose deadline for providing notice of rollover occurs after the annual ARR verification but before June 1, the Transmission Provider shall assume that the rollover will occur and shall consider the Transmission Service entitlement to span the entire allocation year, provided, however, that, if rollover rights for such Transmission Service are not exercised by the applicable deadline, any ARRs associated with such Transmission Service shall revert to the Transmission Provider effective on the date such Transmission Service terminates. The Transmission Provider will verify Eligible Entity existing Transmission Service entitlements as follows:

(1) The following will be performed prior to each annual ARR allocation for Eligible Entities taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service under the Tariff:

(a) The Transmission Provider will obtain source, sink and Reservation Capacity information from the OASIS for each monthly and seasonal period for which ARRs are allocated in which the Transmission Service spans the entire period, or would if or when rolled over, for the current annual allocation;

(i) For a Transmission Service reservation with a source inside the SPP Balancing Authority Area that is not a specific Resource or Resource Market Hub, the Transmission Provider will determine the load Settlement Location that most electrically corresponds to the source on the Transmission Service reservation that will be utilized as the source for candidate ARRs.

(ii) For a Transmission Service reservation with a source outside of the SPP Balancing Authority Area, the interface between the

Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the source for candidate ARRs.

(iii) For a Transmission Service reservation with a sink outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the sink for candidate ARRs.

(b) The Transmission Provider will provide this information to each Eligible Entity for verification; and

(c) Eligible Entities will notify the Transmission Provider within 2 weeks following receipt of this information, identifying and correcting inaccurate data on the OASIS. Otherwise, the Transmission Provider provided data will be considered verified.

(2) The following will be performed prior to each annual ARR allocation for the Eligible Entity taking GFA service:

(a) Each Transmission Owner shall register any GFA for which candidate ARRs are to be provided to the Transmission Owner or the transmission customer under the GFA on the Transmission Provider's OASIS. The Transmission Owner must provide the Transmission Provider with source, sink and Reservation Capacity information for each GFA on the Transmission Provider's OASIS by registering each GFA with the Transmission Provider. The Transmission Provider will use source, sink, and Reservation Capacity information from the GFA registration for each monthly and seasonal period for which ARRs are allocated. If both parties to the GFA are Market Participants with respect to the GFA load, then the parties may jointly inform the Transmission Provider which Market Participant will be allocated the candidate ARRs. If the parties to the GFA do not so inform the Transmission Provider, or if only the Transmission Owner that sold the GFA service is a Market Participant, then the

Transmission Owner that sold the GFA service will be allocated the candidate ARRs associated with the GFA.

(i) For a GFA with a source inside the SPP Balancing Authority Area that is not a specific Resource or Resource Market Hub, the Transmission Provider will determine the load Settlement Location that most electrically corresponds to the source on the Transmission Service reservation that will be utilized as the source for candidate ARRs.

(ii) For a GFA with a source outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the source for the candidate ARRs.

(iii) For a GFA with a sink outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the sink for the candidate ARRs.

(b) If the transmission customer under the GFA is receiving the candidate ARRs, to the extent that the transmission service specified in the GFA is identified as the equivalent of SPP Network Integration Transmission Service, the transmission customer under the GFA must provide the historical peak loads being served under the GFA for the previous three years.

8.2 Bilateral Settlement Schedules and GFA Carve Outs

Market Participants may create Bilateral Settlement Schedules for Energy and Operating Reserve obligations by registering and confirming the parameters of the agreement between buyer and seller as described in the Market Protocols. Both the buyer and seller must confirm the Bilateral Settlement Schedule except when the Bilateral Settlement Schedule is associated with an existing bilateral agreement under Section 8.2.1 of this Attachment AE. Either the buyer or seller may terminate the Bilateral Settlement Schedule at any time except when the Bilateral Settlement Schedule is associated with an existing bilateral agreement under Section 8.2.1 of this Attachment AE. In addition, ~~the Transmission Provider may terminate the~~ Bilateral Settlement Schedules will be administered ~~if either party is in Default~~ pursuant to Attachment X of this Tariff and, if a Bilateral Settlement Schedule is terminated pursuant to Attachment X, the Transmission Provider will resettle with Market Participants as if the Bilateral Settlement Schedule did not exist.

Market Participants may submit Bilateral Settlement Schedule quantities for Energy and Operating Reserve obligation for use in the Day-Ahead Market and may submit Bilateral Settlement Schedule quantities for Energy for use in the Real-Time Balancing Market up to four (4) days following the applicable Operating Day for the initial settlement. New submittals and revisions to previously submitted values may be submitted up to forty-four (44) days following the applicable Operating Day to be included in the final settlement. Submittals not confirmed by both parties will not be included in any settlement execution.

Transactions related to Bilateral Settlement Schedules for Energy must specify the Settlement Location, the MW amount, the buyer, the seller and which market it applies to (Day-Ahead Market or RTBM), and must be for the physical transfer of Energy, with title of the energy transferring from the seller to the buyer at the Settlement Location specified for the transaction. Market Participants that submit Bilateral Settlement Schedules for Energy shall use reasonable efforts to limit the megawatt hours of such transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract. The seller receives an increase in load obligation equal to the specified MW amount and the buyer receives a reduction in load obligation equal to the specified MW amount (the equivalent of a Resource settlement) at the specified Settlement Location.

Transactions related to Bilateral Settlement Schedules for Operating Reserve obligation must specify the buyer, the seller, the Operating Reserve product, the MW obligation transfer and the Reserve Zone within which the obligation transfer applies and must be for the physical transfer of energy associated with the Operating Reserve product, with title of the Operating Reserve product transferring from the seller to the buyer at the Reserve Zone specified for the transaction. The seller receives an increase in Operating Reserve obligation equal to the specified MW and the buyer receives a corresponding decrease in Operating Reserve obligation within the specified Reserve Zone.

8.2.1 Default Procedures for Pre-Existing Bilateral Contracts Transitioning to Integrated Marketplace

The procedures established under this Section 8.2.1 of Attachment AE shall apply to bilateral contracts entered into prior to the start of the Integrated Marketplace~~March 1, 2014~~, where the buyer and seller have not agreed to the terms in the Bilateral Settlement Schedules corresponding to such pre-existing bilateral contracts:

(1) Upon request of the buyer, the Transmission Provider shall review and confirm that a particular bilateral contract exists between the buyer and seller. The Transmission Provider shall schedule a meeting between a designated senior representative of the buyer and seller within 30 days of such a request. The Transmission Provider shall conduct these discussions in accordance with Section 12 of the Tariff. Following confirmation, the buyer may register and confirm a Bilateral Settlement Schedule representing the parameters of the agreement. The Transmission Provider shall confirm that the buyer has submitted Bilateral Settlement Schedule parameters that are consistent with those specified in the bilateral contract;

(2) Subsequent submission by either the buyer or the seller of Bilateral Settlement Schedules for Energy and/or Operating Reserve associated with the registered Bilateral Settlement Schedule in either the Day-Ahead Market and/or RTBM must be consistent with the quantities specified in the bilateral contract. Only the buyer is required to confirm;

(3) Only the buyer may terminate the Bilateral Settlement Schedule;

(4) The Settlement Location for Bilateral Settlement Schedules for Energy shall be the source Settlement Location of the associated transmission service reservation as described under Section 7.1.1(1)(a) of this Attachment AE, as applicable;

(5) The Transmission Provider shall not be a party to Bilateral Settlement Schedules and nothing in this Section 8.2.1 of Attachment AE shall impose on the Transmission Provider any obligation regarding the settlement of financial rights and obligations between the parties to Bilateral Settlement Schedules; and

(6) Nothing in this Section 8.2.1 of Attachment AE shall alter the parties' rights and obligations under preexisting bilateral contracts, limit the right of either party to seek enforcement of such rights and obligations, and/or limit a party's right to obtain appropriate relief, pursuant to Section 206 of the FPA or as otherwise in accordance with the law.

8.6.6 Real-Time Out-of-Merit Amount

An RTBM OOME payment will be made to each Asset Owner with a Resource that receives a Transmission Provider Manual Dispatch Instruction that creates a cost to the Asset Owner or that adversely impacts the Asset Owner's Day-Ahead Market position for Energy and/or Operating Reserve. Resources issued a Manual Dispatch Instruction by a local transmission operator that the Market Monitor determines 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 are not eligible to receive a RTBM OOME payment. RTBM OOME payments made to Asset Owners that received a Manual Dispatch Instruction to address a Local Reliability Issue including Local Emergency Condition shall be recovered locally as described under Section 8.6.7(B). RTBM OOME payments made to Asset Owners that received a Manual Dispatch Instruction to address a reliability issue other than a Local Reliability Issue ~~Emergency Condition~~ shall be recovered regionally under Section 8.8. The amount will be calculated on a Dispatch Interval basis as follows:

(1) If the Manual Dispatch Instruction is for Energy in the up direction and the Energy Offer Curve cost associated with the Resource's additional output attributable to its response ("OOME MW") is greater than the RTBM LMP, the Asset Owner will receive a payment for the difference multiplied by the OOME MW. The payment shall be limited to the amount necessary to compensate the Asset Owner for any under-recovery resulting from its Resource's response to the Manual Dispatch Instruction. The OOME MW is calculated as the positive difference between (i) the lesser of the actual Resource output or the Resource's Manual Dispatch Instruction MW and (ii) the Resource's economic operating point. The Resource's economic operating point is calculated as described under Section 8.6.5(4)(d);

(2) If the Manual Dispatch Instruction is for Energy in the down direction, including a Resource de-commitment and the RTBM LMP is greater than the Day-Ahead Market LMP, the Asset Owner will receive a payment equal to the difference multiplied by the Resource's reduction in output attributable to its response

("OOME MW"). The payment shall be limited to the amount necessary to compensate the Asset Owner for any increase in net settlement costs resulting from its response to the Manual Dispatch Instruction. The OOME MW is calculated as the maximum of zero (0) or the difference between the Resource's Day-Ahead Market cleared Energy MW and the greater of (i) actual Resource output or (ii) the Resource's Manual Dispatch Instruction MW;

(3) If the Manual Dispatch Instruction or a Resource de-commitment instruction, causes the RTBM cleared amount of an Operating Reserve product to be less than the Day-Ahead Market cleared amount of the corresponding Operating Reserve product and the RTBM MCP is greater than the Day-Ahead Market MCP, the Asset Owner will receive a payment for the difference multiplied by the OOME Operating Reserve MW. The OOME Operating Reserve MW is calculated as the maximum of zero (0) or the difference between the Resource's Day-Ahead Market cleared Operating Reserve MW and the Resource's RTBM cleared Operating Reserve MW.

(4) To the extent that additional costs are incurred as a direct result of a Manual Dispatch Instruction that are not addressed through the compensation mechanisms described in (1) through (3) above, 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.

8.6.7 Reliability Unit Commitment Make Whole Payment Distribution Amount

An RTBM system-wide and local charge will be calculated at each Settlement Location for each Asset Owner for each hour in order to fund the payments made under Section 8.6.5. The system-wide amount will be determined by multiplying an Asset Owner's system-wide distribution volume by a daily system-wide RUC make whole payment rate as described in Section 8.6.7(A) of this Attachment AE. The local amount for each Settlement Area impacted by a Local Reliability Issue will be determined by multiplying an Asset Owner's local Settlement Area distribution volume by a daily local Settlement Area RUC make whole payment rate as described in Section 8.6.7(B) of this Attachment AE.

A. The RUC System-Wide Make Whole Payment Distribution Amount shall be calculated as follows:

The RUC System-Wide Make Whole Payment Distribution Amount =
[(RUC System-Wide Make Whole Payment Distribution Rate) *
(RUC System-Wide Make Whole Payment Distribution Volume)]

(1) The RUC System-Wide Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day as calculated under Section 8.6.5 excluding make whole payments made to Resources committed to address a Local Reliability Issue by the Transmission Provider at the request of a local transmission operator or committed by a local transmission operator to address a Local Emergency Condition, divided by the sum of Asset Owners' RUC System-Wide Make Whole Payment Distribution Volumes for all Settlement Locations for the entire Operating Day.

(2) An Asset Owner's RUC System-Wide Make Whole Payment Distribution Volume at a Settlement Location for an hour is equal to the sum of following values that are calculated for each Dispatch Interval within the hour:

(a) The absolute value of the sum of actual Real-Time Settlement Location deviations from Day-Ahead Market cleared amounts for load, virtual offer transactions and interchange transactions except that, during any Dispatch Interval in which the Transmission Provider has declared an Emergency Condition due to a capacity shortage, Real-Time actual load deviations from Day-Ahead Market cleared amounts shall be limited to deviations associated with actual Real-Time load in excess of amounts cleared in the Day-Ahead Market;

(b) For Resources cleared in the Day-Ahead Market, (a) the positive difference between the RTBM Resource applicable minimum limits and Day-Ahead Market Resource cleared Energy quantity; or (b) if the Resource has cleared regulation in the RTBM and has not cleared regulation in the Day-Ahead Market, the positive difference between (1) the RTBM Resource regulation minimum limit and (2) the greater of the Day-Ahead Market Resource cleared Energy quantity or the Resource's Day-Ahead Market regulation minimum limit, provided that:

(i) The applicable RTBM Resource minimum limit is greater than the comparable Day-Ahead Market Resource minimum limit by more than the Resource's Operating Tolerance; and

(ii) The applicable RTBM Resource minimum limit is greater than the Day-Ahead Market cleared Energy amount; and

(iii) The Resource received a Dispatch Instruction less than or equal to the RTBM applicable minimum limit for at least one Dispatch Interval in the hour.

(c) For Resources cleared in the Day-Ahead Market, (a) the positive difference between the Resource Day-Ahead Market cleared Energy quantity and the RTBM Resource applicable maximum limit or (b) if the Resource has cleared regulation in the RTBM and has not cleared regulation in the Day-Ahead Market, the positive difference between (1) the lesser of the Resource's RTBM regulation maximum limit or the Resource's Day-Ahead Market

Resource cleared Energy quantity and (2) the Resource's RTBM regulation maximum limit, provided that:

(i) The applicable RTBM Resource maximum limit is less than the comparable Resource maximum limit submitted for use in the Day-Ahead Market by more than the Resource's Operating Tolerance; and

(ii) The applicable RTBM Resource maximum limit is less than the Day-Ahead Market cleared Energy amount; and

(iii) The Resource received a Dispatch Instruction greater than or equal to the RTBM applicable maximum limit for at least one Dispatch Interval in the hour.

(d) For Resources cleared in the Day-Ahead Market, the Resource's Day-Ahead Market cleared amount if that Resource is off-line in the RTBM and if the Resource has not been de-committed by the Transmission Provider;

(e) For Resources that cleared in the Day-Ahead Market that are not able to follow Dispatch Instructions, the absolute value of the difference between a Resource's actual output and the Resource's economic operating point. The Resource's economic operating point is calculated as described under Section 8.6.5(4)(d);

(f) For Resources that were not offered in the Day-Ahead Market and that self-committed following the close of the Day-Ahead Market, and for Resources that were offered and not cleared in the Day-Ahead Market and that self-committed following the close of the Day-Ahead RUC, the actual Resource output if the Resource received a Dispatch Instruction less than or equal to the RTBM applicable minimum limit for at least one Dispatch Interval in the hour;

(g) A Resource's economic operating point, as calculated as described under Section 8.6.5(4)(d), for Resources that were committed following the close of the Day-Ahead Market if that Resource is off-line in the RTBM and that Resource was not de-committed by the Transmission Provider; and

(h) The absolute value of a Resource's URD if that Resource operated outside of its Operating Tolerance and the Resource has not been exempted from URD as described under Section 6.4.1.1 of this Attachment AE.

B. RUC Local Settlement Area Make Whole Payment Distribution Amount shall be calculated as follows:

RUC Local Settlement Area Make Whole Payment Distribution Amount =

[(RUC Local Settlement Area Make Whole Payment Distribution Rate) * (RUC Local Settlement Area Make Whole Payment Distribution Volume)]

(1) The RUC Local Settlement Area Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day for a Settlement Area as calculated under Sections 8.6.5 and 8.6.6 of this Attachment AE for Resources committed ~~within a Settlement Area~~ by the Transmission Provider at the request of a local transmission operator or by a local transmission operator to address a Local Reliability Issue in the Settlement Area, divided by the sum of Asset Owners' RUC Local Settlement Area Make Whole Payment Distribution Volumes within the impacted Settlement Area for the entire Operating Day.

(2) An Asset Owner's RUC Local Settlement Area Make Whole Payment Distribution Volume for the impacted Settlement Area for an hour is equal to that Asset Owner's Reported Load in that Settlement Area for that hour.

3. Mitigation Measures for Economic Withholding – Market Power in Energy and Operating Reserve

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 manually committed by the Transmission Provider or selected for commitment by a local transmission operator ~~in the Day-Ahead or Intra-Day RUC processes~~ as described in Attachment AE, Sections 4.5.2, 4.5.3, 5.1.2, 5.2.2(3), 5.2.2(4), ~~5.2.2(5),~~ 6.1.2(3), and 6.1.2(4)~~, and 6.1.2(5)~~.

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 Areas shall be listed in Addendum 1 of this Attachment AF. Any new or modifications to existing Frequently Constrained Areas are subject to prior Commission approval.

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 or more frequently as the Market Monitor deems necessary. The Transmission Provider may propose an area be designated or undesignated as a Frequently Constrained Area if the Transmission Provider believes that conditions have changed with respect to the binding transmission constraint or binding Reserve Zone constraints that define the Frequently Constrained

Area. The Market Monitor shall evaluate any proposed change and seek comments from the Market Participants before recommending to designate, modify, or undesignate a Frequently Constrained Area. Subject to any applicable confidentiality requirements, the Market Monitor will provide any interested Market Participants with a description of its supporting analysis to allow comment on the proposed designation changes. The Market Monitor will recommend any changes to the Frequently Constrained Areas to the SPP Board of Directors for approval.

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. The mitigated Energy Offer Curve may be updated up to 1100 hours on the day before the Operating Day 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 1100 hours on the day before the Operating Day will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day; 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.

A. The Energy Offer Curve conduct thresholds are as follows:

(1) For Resources with local market power as described in Section 3.1(4), the conduct threshold is a 10% increase above the mitigated Energy Offer Curve;

(2) For Resources located in a Frequently Constrained Area and not subject to Section 3.2(A)(1), the conduct threshold is a 17.5% increase above the mitigated Energy Offer Curve;

(3) For all other Resources the conduct threshold is a 25% increase above the mitigated Energy Offer Curve.

B. 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 Section 3.1; and

(3) The Resource either:

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

(b) Has local market power as described in Section 3.1(4).

An Energy Offer below $25/MWh will not be subject to mitigation measures for economic withholding.

C. The mitigated energy offer shall be the Resource's short-run marginal cost of producing energy as determined by the unit's heat rate; 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.

D. Opportunity cost shall be an estimate of the Energy and Operating Reserve Markets revenues net of short run marginal costs for the marginal foregone 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:

Mitigated Energy Offer (\$/MWh) = HeatRate (mmBtu/MWh) *

Performance Factor * Total Fuel Related Costs ($/mmBtu) + EOC VOM ($/MWh) + Opportunity Costs ($/MWh)

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.

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.

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 for Energy Offers for Non-Dispatchable Variable Energy Resources will occur.

E. 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. Intra-day changes to the mitigated energy offer curve must follow the mitigated offer development guidelines in the Market Protocols and will be validated by the Market Monitor.

F. In all cases under this Section 3.2, cost data submitted for the development of mitigated offers, including additional 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 1100 hours on the day before the Operating Day 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.

A. The Start-Up and No-Load Offer conduct thresholds are as follows:

(1) For Resources with local market power as described in Section 3.1(4), the conduct threshold is a 10% increase above the mitigated Start-Up or mitigated No-Load Offer, as applicable;

(2) For all other Resources the conduct threshold is a 25% increase above the mitigated Start-Up or mitigated No-Load Offer, as applicable.

B. 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 Section 3.1; and

(3) The Resource either:

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

(b) Has local market power as described in Section 3.1(4).

C. 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"), maintenance costs attributed to starts, and additional labor costs, if required above normal station staffing levels. The following formula shall apply to all mitigated Start-Up Offers:

Mitigated Start-Up Offer ($/Start) = [Start Fuel (mmBtu/Start) * Total Fuel Related Costs ($/mmBtu) * Performance Factor] + [Station Service (MWh/Start) * Station Service Rate ($/MWh)] + Start VOM ($/Start) + Start Additional Labor Cost ($/Start)

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.

D. The mitigated No-Load Offer shall be the hourly fixed cost required to create a monotonically increasing mitigated Energy Offer Curve. It shall be calculated according to either of two methods:

(1) No-Load Fuel Approach

Mitigated No-Load Offer ($/hour) = No Load Fuel (mmBtu/hour) * Performance Factor * (No-Load VOM ($/mmBtu) + Total Fuel Related Cost ($/mmBtu)

(2) No-Load Cost Approach

Mitigated No-Load Offer ($/hour) =

(Heat Input at Minimum Economic Capacity Operating Limit (mmBtu) * Performance Factor *

(Total Fuel Related Cost ($/mmBtu) + No Load VOM ($/mmBtu))) –

(Incremental Cost up to Minimum Economic Capacity Operating Limit ($/MWh) * Minimum Economic Capacity Operating Limit (MW))

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.

E. 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. 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.

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

F. In all cases under this Section 3.3, cost data submitted for the development of mitigated offers, including additional opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this 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. The mitigated Operating Reserve Offers may be updated up to 1100 hours on the day before the Operating Day 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 1100 hours on the day before the Operating Day will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day; 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. The offer conduct thresholds for each of the Operating Reserve products are as follows:

   (1) For Resources with local market power as described in Section 3.1(4), the conduct threshold is a 10% increase above the mitigated offer for the applicable Operating Reserve Offer;

   (2) For all other Resources, the conduct threshold is a 25% increase above the mitigated offer for the applicable Operating Reserve Offer.

B. Any Operating Reserve Offer exceeding the applicable threshold, except offers below $10/MWh, will be deemed excessive. 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 Section 3.1; and

   (3) The Resource either:

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

      (b) Has local market power as described in Section 3.1(4).

C. 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:

Mitigated Spinning Reserve Offer ($/MW) ≤
(Additional Fuel Cost($/Hr) + Additional Maintenance Cost ($/Hr) + Condensing Power Cost ($/Hr)) /
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

D. The mitigated Regulation-Up 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:

Mitigated Regulation-Up Offer ($/MW) <

Cost Increase due to Heat Rate Increase during non-steady state operation ($/MW) +

Cost Increase in VOM ($/MW) + Uncompensated Cost ($/MW)

E. The mitigated Regulation-Down 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:

Mitigated Regulation-Down Offer ($/MW) <

Cost Increase due to Heat Rate Increase during non-steady state operation ($/MW) +

Cost Increase in VOM ($/MW) + Uncompensated Cost ($/MW)

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

F. 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.

G. 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.

H. In all cases under this Section 3.4, cost data submitted for the development of mitigated offers, including additional 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 in order to ensure that the Market Participant has correctly applied the formulas and definitions in Sections 3.2, 3.3, 3.4 and 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, the mitigated offer calculated by the Market Monitor shall be used. 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~~performing price corrections and resettlements as described in Section 8.4 of Attachment AE of this Tariff and the Market Protocols~~.

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 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 threshold for Resources manually committed in accordance with Attachment AE, Sections 5.2.2(3), 6.1.2(3), and 6.1.2(4) of this Tariff: twenty-five percent (25%) increase.

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 additional 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 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. 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 impact test thresholds are as follows: At market start, the LMP impact threshold is five dollars ($5) per megawatt hour, the MCP impact threshold is five dollars ($5) per megawatt hour, and the make whole payment impact threshold is five dollars ($5) per megawatt hour. At the beginning of each six (6) month period after the market start, the LMP and MCP impact thresholds will be increased ten dollars ($10) per megawatt hour and the make whole payment impact threshold will be increased by ten dollars ($10) per megawatt hour unless the Market Monitor finds market behavior that warrants keeping the threshold constant for the next six (6) months. The periodic increases will continue until 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 relevant conduct threshold, as specified in Section 3.2, 3.3, or 3.4 of this Attachment AF.

B. If a Market Participant anticipates submitting an offer that will exceed the mitigated offer by more than the relevant conduct threshold, it may contact the Market Monitor to provide an explanation of the changes in its offer. If the Market Participant's pre-offer explanation indicates to the Market Monitor that the questioned behavior is consistent with competitive behavior, the Transmission Provider will not impose mitigation with respect to that offer unless and until circumstances are deemed to warrant it, and the Transmission Provider or the Market Monitor so notifies the Market Participant. In circumstances where, following a Market Participant's pre-offer explanation, both the conduct and impact thresholds are violated but no mitigation is imposed, the Market Monitor will record such instances and will report such instances to the Commission's Office of Enforcement, or its successor organization, every three months during the first year of Integrated Marketplace operations, and yearly thereafter. To the extent that the report contains sensitive data, the Market Monitor should include any such data in a non-public version of the report.

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.

4. Mitigation Measures for Virtual Energy Bids and Virtual Energy Offers

If a determination is made, as specified in Section 4.6.3 of Attachment AG, that excessive divergence exists and the divergence is the result of the Virtual Energy Bids or Virtual Energy Offers of one or more Market Participants, the Transmission Provider shall impose mitigation measures. The mitigation measures will restrict the Market Participants that caused the divergence from submitting any Virtual Energy Bids or Virtual Energy Offers at the Settlement Locations where the Market Participant's Virtual Energy Bids or Virtual Energy Offers caused the excessive divergence~~ and at any electrically similar Settlement Location. An electrically similar Settlement Location, for purposes of this section, is any Settlement Location with a shift factor to a congested flowgate of the same sign and of a magnitude equal to or exceeding that of a Settlement Location where the Market Monitor has determined that the Market Participant's Virtual Energy Bids or Virtual Energy Offers caused excessive divergence, as described under Section 4.6.3 of Attachment AG~~. The mitigation measures shall be imposed for a period of three (3) months after which time the restriction will no longer apply.

4. Market Monitoring

4.1 Markets to be Monitored

The Market Monitor will monitor Markets and Services. The Market Monitor will not monitor bilateral energy, transmission or capacity markets and services not administered, coordinated or facilitated by SPP, except to assess the effect of these markets and services on Markets and Services, or the effects of Markets and Services on these unmonitored markets. Similarly, the Market Monitor will not monitor the energy, transmission or capacity markets and services in regions adjacent to the SPP Region except to assess the effect of these markets and services on Markets and Services, or the effects of Markets and Services on these adjacent markets.

4.2 Market Monitoring Scope

The Market Monitor will implement the Plan. The markets will require continuous monitoring by the Market Monitor. The Market Monitor will monitor Markets and Services by reviewing and analyzing market data and information including, but not limited to:

(a) Resource registration data;

(b) Resource Offer data including non-price related offer parameters required for use in either the Day-Ahead Market, Reliability Unit Commitment process and/or Real-Time Balancing Market;

(c) Demand Bids for the purchase of Energy in the Day-Ahead Market;

(d) Virtual Energy Bids for the purchase of Energy in the Day-Ahead Market and Virtual Energy Offers for the sale of Energy in the Day-Ahead Energy Market;

(e) Export Interchange Transaction Bids and Import Interchange Transaction Offers for the purchase and sale of Energy in the Day-Ahead Market and the Real-Time Balancing Market;

(f) Actual commitment and dispatch of Resources, including but not limited to Resource MW capability and output, MVAR capability and output, status, and outages;

(g) Locational Marginal Prices and zonal Market Clearing Prices at all Settlement Locations in or affecting any of Markets and Services;

(h) SPP Balancing Authority Area data, including but not limited to demand, area control error, Net Scheduled Interchange, actual total net interchange, and forecasts of operating reserves and peak demand;

(i) Conditions or events both inside and outside the SPP Balancing Authority Area affecting the supply and demand for, and the quantity and price of, products or services sold or to be sold in Markets and Services;

(j) Information regarding transmission services and rights, including the estimating and posting of Available Transfer Capability ("ATC") or Available Flowgate Capability ("AFC"), administration of this Tariff, the operation and maintenance of the transmission system, any auctions or other markets for transmission rights, and the reservation and scheduling of transmission service;

(k) Information regarding the nature and extent of transmission congestion in the region and, to the extent practicable, transmission congestion on any other system that affects Markets and Services, including but not limited to causes of, costs of and charges for transmission congestion, transmission facility loading, MVA capability, line status and outages;

(l) Settlement data for the Markets and Services;

(m) Any information regarding collusive or other anticompetitive or inefficient behavior in or affecting any of Markets and Services; and

(n) Generation resource operating cost data for estimating resource incremental cost, including fuel input costs, heat rates where applicable, start-up fuel requirements, environmental costs and variable operating and maintenance expenses.

(o) Logs of transmission service requests and Generation Interconnection Requests along with the disposition of each request and the explanation of any refused requests: and

(p) Any additional Resource and transmission facility outage data not otherwise provided for in this Section 4.2.

(q) GFA Carve Out Schedules.

4.2.1 Additional Market Monitor Duties

(a) In addition to the monitoring of market Data and Information, the Market Monitor may communicate with SPP Staff and Market Participants at any time for the purpose of monitoring and assessing market conditions.

(b) The Market Monitor shall evaluate the effectiveness of Markets and Services in signaling the need for investment in new generation, transmission or demand response infrastructure and report on its findings at least annually.

4.3 Referrals to the Commission

(a) The Market Monitor shall report suspected market violations, as defined in 18 CFR 35.28(b)(8), to FERC's Office of Enforcement (or its successor organization) staff in accordance with the FERC's reporting protocols for referrals by market monitors as specified in 18 C.F.R. § 35.28(g)(3)(iv) in a timely manner. Any such reports by the Market Monitor to FERC Staff shall be on a confidential basis, and all information and documents included in such reports will not be released to any other party except to the extent FERC directs or authorizes such release, unless such information and documents are already in the public domain.

4.4 Monitoring for Potential Integrated Marketplace Manipulation

The Market Monitor will monitor for potential instances of market manipulation in the Integrated Marketplace. Such actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices (including actions resulting in excessive day-ahead clearing prices), market conditions, or market rules for electric energy or electric products are prohibited. As listed by the FERC, prohibited behavior includes (a) wash trades, (b) submission of false data, (c) actions to cause artificial congestion and (d) collusive acts. The Market Monitor will report any market manipulation in the Integrated Marketplace in a timely manner.

4.5 Monitoring for Potential Transmission Market Power Activities

The Market Monitor shall monitor Markets and Services for the exercise of transmission market power by reviewing and analyzing data and information related to the availability of transmission facilities that impact access to services under this Tariff. The Market Monitor will monitor for activities particularly with respect to the withholding of transmission facilities or transmission capacity, including activities such as but not limited to, the following:

(a) Physical withholding by Transmission Owners by providing improper information related to the availability of transmission, such as information related to the capability or other modeling data used by SPP for use in system operations;

(b) Economic withholding by Transmission Owners through the use of methods and data for estimating costs of interconnection and system upgrades that is not comparable for affiliates and non-affiliates;

(c) Unavailability of transmission facilities through planned and unplanned maintenance outages that routinely exceed historical baselines; and

(d) Withholding of transmission capacity through excess reservations that are not actually used.

The Market Monitor shall refer any perceived market design flaws and recommended Tariff language changes to the Commission's Office of Energy Market Regulation (or its successor office/organization). In addition, the Market Monitor shall refer any instance(s) of the suspected exercise of transmission market power directly to the Commission's Office of Enforcement (or its successor organization) utilizing the protocols for referrals to the Commission for suspected instances of the exercise of market power that may be part of a suspected market violation, such as manipulation, in accordance with 18 C.F.R. § 35.28(g)(3)(iv). Where appropriate, the Market Monitor shall also provide the FERC with an estimate of damages equal to (i) the effect on prices multiplied by

(ii) the affected energy produced by the Transmission/Generation Owner. The Market Monitor may also request the FERC to impose additional sanctions and penalties, which may consist of a fixed dollar amount based on each instance, or an amount up to (i) the effect on prices multiplied by (ii) the affected energy produced by Market Participants other than the Transmission/Generation Owner. All such referrals by the Market Monitor to FERC will be on a confidential basis, and all information and documents included in such reports will not be released to any other party except to the extent FERC directs or authorizes such release.

4.6 Monitoring for Market Participant Behavior Possibly Warranting Mitigation

The Market Monitor shall monitor Markets and Services for potential abuse associated with the following categories of Market Participant behavior: (1) economic withholding; (2) uneconomic production; (3) physical withholding; (4) uneconomic Virtual Bids and Virtual Offers; and (5) gaming related to GFA Carve Out Schedules. The mitigation measures for each of the behaviors identified in items (1) through (4) of this paragraph are described in Attachment AF. When the Market Monitor determines that there is sufficient credible information about a specific abusive practice, the issue will be referred to the Commission's Office of Enforcement (or its successor organization). Nothing in this section shall limit the Market Monitor's obligation to refer other suspected market violations to the Commission's Office of Enforcement, even where suspected behavior does not fall explicitly within the abovementioned categories or descriptions.

4.6.1 Uneconomic Production

The Market Monitor will monitor for cases where uneconomic production by a Resource causes congestion on transmission facilities or price separation between Reserve Zones that is not justified by reliability concerns. The provisions of this Section 4.6.1 shall not apply to Demand Response Resources.

(a) Potential uneconomic production will be indicated, and subject to further analysis as described in (b) of this Section 4.6.1, when the Resource has a positive Resource-to-Load Distribution Factor and any of the following conditions are met:

(1) a Resource is identified with an incremental energy offer price less than 50 percent of the applicable reference level; or

(2) a Resource is determined to be generating outside of its Operating Tolerance; or

(3) time-based or other (non-time and non-dollar) offer parameters contribute to congestion on transmission facilities or price separation between Reserve Zones~~a Resource is subject to a time-based or other resource offer parameter (non-time and non-dollar based) that violates any of the thresholds specified in Section 3.6 of Attachment AF~~.

(b) For any Resource meeting the conditions described in (a) of this Section 4.6.1, the Market Monitor shall determine whether: (i) the MW impact from uneconomic production associated with such Resource is exacerbating the transmission congestion or binding a Reserve Zone; and (ii) the uneconomic production is not obviously justified by reliability or other operational concerns.

The Market Monitor will conduct evaluations as specified above and other related assessments to determine if there is sufficient credible information to justify referral to the Commission.

4.6.2 Monitoring for Virtual Energy Bids and Virtual Energy Offers

The Market Monitor will monitor the level of divergence between the Day-Ahead Market LMPs and the Real-Time Balancing Market LMPs. Section 4.6.3 defines the monitoring metric and thresholds to be used in determining the existence of excessive LMP divergence. In the case that there is excessive LMP divergence, the Market Monitor will determine if the LMP divergence is attributable to the Virtual Energy Bid and Virtual Energy Offer behavior of one or more Market Participants. If the Market Monitor identifies one or more Market Participants as having caused the excessive LMP divergence through Virtual Energy Bid and Virtual Energy Offer behavior, then the Transmission Provider shall impose mitigation measures described in Section 4.0 of Attachment AF.

4.6.3 Metric and Threshold Specifications

The Market Monitor will compute the hourly LMP deviation between the Day-Ahead Market and Real-Time Balancing Market using the following formula: $[(LMP_{RTBM} / LMP_{DA\ Market}) - 1] * 100$. The average hourly LMP deviation is computed over a rolling four (4) week period or any other period that the Market Monitor determines is appropriate. If the four (4) week rolling average is below negative ten percent (-10%) or in excess of ten percent (10%), then the divergence is considered excessive and additional analysis is required. ~~The provisions of this Section 4.6.1 shall not apply to Demand Response Resources.~~

4.6.4 Physical Withholding

The Market Monitor will monitor for physical withholding of capacity from the Energy and Operating Reserve Markets, and unavailability of facilities. Physical withholding and unavailability of facilities may include:

(a) Declaring that a Resource has been derated, forced out of service or otherwise been made unavailable for technical reasons that are untrue or that cannot be verified;

(b) Refusing to provide offers or schedules for a Resource when it would otherwise have been in the economic interest to do so without market power;

(c) Operating a Resource in real-time to produce an output level that is less than the dispatch instruction;

(d) Derating a transmission facility for technical reasons that are not true or verifiable;

(e) Operating a transmission facility in a manner that is not economic and that causes a binding transmission constraint or binding reserve zone or local reliability issue; and

(f) Declaring that the capability of Resources to provide Energy or Operating Reserves is reduced for reasons that are not true or verifiable.

Market Participants will not be deemed to be physically withholding if they are following the directions of the SPP Balancing Authority, Reliability Coordinator, or applicable reliability standards. In addition, Market Participants will not be determined to have physically withheld if they are selling into another market at a higher price.

4.6.4.1 Thresholds for Identifying Physical Withholding of Resource Capacity

4.6.4.1.1 A Market Participant is deemed to be physically withholding capacity in a Frequently Constrained Area if all of the following conditions exist:

(a) One or more of the transmission constraints or Reserve Zone constraints that define the Frequently Constrained Area are binding; and

(b) The Market Participant controls or owns a Resource located in the Frequently Constrained Area that satisfies condition 4.6.4(a), 4.6.4(b), 4.6.4(c), or 4.6.4(f) of this Attachment AG.

4.6.4.1.2 A Market Participant is deemed to be physically withholding capacity in an area not designated as a Frequently Constrained Area if all of the following conditions exist:

(a) One or more transmission constraints are binding or a Reserve Zone is binding; and

(b) The Resource(s) meets either of the following criteria (1) or (2);

(1) Such Resource(s) satisfy one of the conditions in Sections 4.6.4(a), 4.6.4(b), or 4.6.4(f) of this Attachment AG and the total withheld capacity exceeds the lower of 5 percent of the total capability owned or controlled by the Market Participant or 200 MW; or

(2) Where the real-time output of each such Resource is less than the Resource's Operating Tolerance defined in Attachment AE, Section 6.4.1 of this Tariff and the Resource is not exempt from Uninstructed Resource Deviation under Attachment AE, Section 6.4.1.1 of this Tariff.

4.6.4.2 Thresholds for Screening of Potential Physical Withholding of Transmission Facilities

A transmission facility fails the physical withholding screen if either of the following conditions is met:

(a) The transmission facility satisfies a condition in Section 4.6.4(d) or 4.6.4(e) of this Attachment AG ~~and has been determined to have contributed to the constraints, congestion or Local Reliability Issues as described in Section 4.6.4.2(a) of this Attachment AG~~; or

(b) The Market Monitor identifies a pattern of scheduling outages resulting in increased market costs compared to an alternative and lower cost impact outage schedule.

4.6.4.3 Sanctions

The Market Monitor will record instances where Market Participants have failed the screens in Sections 4.6.4.1 and 4.6.4.2 of this Attachment AG and notify the Commission's Office of Enforcement, or successor organization, of such behavior. In the event the Market Monitor determines there is credible evidence of a market violation, the Market Monitor shall make a referral to the Commission as described in Section 4.3 of this Attachment AG.