July 10, 2014

VIA ELECTRONIC FILING

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. ER14-_____-000
Submission of Tariff Revisions to Attachment AE for the Integrated Marketplace

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. 824d, and Section 35.13 of the Federal Energy Regulatory Commission's ("Commission") Regulations, 18 C.F.R. § 35.13, Southwest Power Pool, Inc. ("SPP") submits revisions to its Open Access Transmission Tariff ("Tariff")[1] to revise Attachment AE, which contains the bidding, offering and dispatching responsibilities of the Transmission Provider[2] and Market Participants relating to the Integrated Marketplace and sets forth the operation, pricing and settlement of the Day-Ahead Market, the Real-Time Balancing Market ("RTBM") and the Transmission Congestion Rights ("TCRs") Market.[3] SPP requests a September 8, 2014 effective date for the proposed Tariff revisions.

I. BACKGROUND

SPP is a Commission-approved Regional Transmission Organization ("RTO").[4] It is an Arkansas non-profit corporation with its principal place of

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1 Southwest Power Pool, Inc., FERC Electric Tariff, Sixth Revised Volume No. 1. Italicized language in the Tariff represents language that is pending before the Commission in other dockets.

2 Defined terms not otherwise provided herein shall have the definition ascribed in the Tariff.

3 *See* Tariff at Attachment AE, Section 1- Introduction.

4 *See Sw. Power Pool, Inc,* 109 FERC ¶ 61,009 (2004), *order on reh'g*, 110 FERC ¶ 61,137 (2005).

business in Little Rock, Arkansas. SPP has 76 Members, including 14 investor-owned utilities, 11 municipal systems, 13 generation and transmission cooperatives, 5 state agencies, 11 independent power producers, 12 power marketers and 10 independent transmission companies. As an RTO, SPP administers open access Transmission Service over approximately 48,930 miles of transmission lines covering portions of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas, across the facilities of SPP's Transmission Owners,[5] and administers the Integrated Marketplace, which SPP commenced on March 1, 2014.

II. DESCRIPTION AND JUSTIFICATION FOR TARIFF REVISIONS

As discussed herein, SPP proposes several revisions to Attachment AE of the Tariff as applicable to the Integrated Marketplace. The revisions proposed herein were developed through the stakeholder process and approved by the SPP Board of Directors. The Tariff revisions proposed in this area are necessary to refine aspects of the Integrated Marketplace that require further description or clarification. The proposed revisions include enhancements to existing design features and the addition of enhancements to broaden access to the Integrated Marketplace and allow SPP to effectively administer the Day-Ahead, RTBM, and TCR Markets within the SPP region.

A. SPP Stakeholder Process

The Tariff revisions proposed herein were developed and approved through SPP's customary stakeholder process. Multiple stakeholder working groups were, and continue to be, involved with further refinements to the language contained in the Tariff which are necessary to increase transparency of the Integrated Marketplace. Where appropriate, SPP stakeholders may also approve enhancements to the Integrated Marketplace to improve the services SPP provides under the Tariff.

The majority of the Tariff modifications proposed herein were developed by SPP's Market Working Group ("MWG") and Regional Tariff Working Group ("RTWG"), the two SPP working groups responsible for Integrated Marketplace Protocols[6] ("Market Protocols") development and the Tariff, respectively. The Operating Reliability Working Group ("ORWG") also reviews proposed Market Protocol changes related to Integrated Marketplace operations to ensure reliability

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[5] *See Sw. Power Pool, Inc.*, 89 FERC ¶ 61,084 (1999); *Sw. Power Pool, Inc.*, 86 FERC ¶ 61,090 (1999); *Sw. Power Pool, Inc.*, 82 FERC ¶ 61,267, *order on reh'g*, 85 FERC ¶ 61,031 (1998).

[6] The Integrated Marketplace Protocols are posted on SPP's website at: http://www.spp.org/section.asp?group=215&pageID=27.

impacts, if any, are identified. After thorough vetting and approval by these groups, proposals to revise the Tariff are presented to the Market and Operations Policy Committee ("MOPC") for review and the SPP Board of Directors for final approval for filing.[7] SPP recognizes that stakeholder approval does not by itself cause a filing to be just and reasonable; however, SPP requests that the Commission extend appropriate deference to the wishes of its stakeholders regarding the revisions proposed in this filing, consistent with Commission precedent.[8]

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[7] *See* SPP Board of Directors meeting minutes posted at http://www.spp.org/section.asp?group=113&pageID=27. MPRRs 91 and 113 were approved on April 30, 2013 (Board of Directors/Members Committee Meeting Minutes No. 151 at Agenda Item 3). MPRRs 122 and 124 were approved on July 30, 2013 (Board of Directors/Members Committee Meeting Minutes No. 153 at Agenda Item 3). MPRR 144 and TRRs 121 and 124 were approved on April 29, 2014 (Board of Directors/Members Committee Meeting Minutes No. 158 at Agenda Item 3).

[8] The Commission has previously recognized that provisions approved through RTO stakeholder processes are due deference. *See Sw. Power Pool, Inc.*, 127 FERC ¶ 61,283, at P 33 (2009) (noting that the Commission "accord[s] an appropriate degree of deference to RTO stakeholder processes"); *New Eng. Power Pool*, 105 FERC ¶ 61,300, at P 34 (2003) (Commission approval of transmission cost allocation proposal based upon an extensive and thorough stakeholder process); Policy Statement Regarding Regional Transmission Groups, 1991-1996 FERC Stats. & Regs., Regs. Preambles ¶ 30,976, at 30,872 (1993) (the Commission will afford the appropriate degree of deference to the stakeholder approval process). The Commission's deference to RTO stakeholder processes has been upheld by the courts. *See* Pub. Serv. Comm'n of Wis. v. FERC, 545 F.3d 1058, 1062-63 (D.C. Cir. 2008) (noting that the Commission often gives weight to RTO proposals that reflect the position of the majority of the RTO's stakeholders) (quoting Am. Elec. Power Serv. Corp. v. Midwest Indep. Transmission Sys. Operator, Inc., 122 FERC ¶ 61, 083, at P 172 (2008)).

B. Revisions to Attachment AE

1. *Contingency Reserve Deployment Period*

SPP proposes to revise the definition for Contingency Reserve Deployment Instruction to read as follows:

> "The time allowed to deploy Contingency Reserve following the issuance of a ~~reserve sharing event~~ Contingency Reserve Deployment Instruction, as specified in the ~~SPP Criteria~~ Market Protocols."

The purpose of this revision is to point the Market Participant to the Market Protocols, rather than the SPP Criteria, for the timeframe allowed to deploy Contingency Reserves following the issuance of a directive by SPP. The issuance of a directive is identified as the Contingency Reserve Deployment Instruction.[9] The time allotment before deployment of contingency reserves set by the Market Protocols is ten (10) minutes.[10] The proposed addition of this clarifying language does not substantively revise any current operational procedure or function. The proposed revision to the definition of Contingency Reserve Deployment Instruction to reference the Market Protocol defined Contingency Reserve Deployment Instruction is more accurate than a reference to the lowercase and the non-defined term "reserve sharing event."

In summary, the proposed revision to the definition of Contingency Reserve Deployment Instruction provides clarifying language to increase transparency between the Tariff and the Market Protocols. As the modifications to the definition of Contingency Reserve Deployment Instruction proposed herein provide a correct reference to the proper governing document, the Commission should approve this clarification as just and reasonable and in the public interest.

2. *Demand Response Resource Calculation*

In this filing, SPP proposes to revise Section 4.1.2.1(1)(i) and (ii) of Attachment AE to replace the term "deployment" with "commitment" as it relates to the calculation of the output of Demand Response Resource during real-time

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9 *See* Tariff at Attachment AE, 1.1 Definitions C. Contingency Reserve Deployment Instruction is defined as "[a]n instruction issued by the Transmission Provider to Resources cleared for Contingency Reserve in the Real-Time Balancing Market to deploy a specific Megawatt quantity of Contingency Reserve as communicated as a component of the Setpoint Instructions."

10 *See* SPP Market Protocols at Section 1- Glossary C, Contingency Reserve Deployment Period (setting the timeframe at ten (10) minutes within which a resource has to deploy Contingency Reserve).

operations. The Tariff consistently references assets being committed for use in the Integrated Marketplace, rather than deployed. Therefore, using "commitment" is more appropriate as an indicator of the actual status of the Demand Response Resource during a Dispatch Interval.

Additionally, SPP proposes a new section (c) of Section 4.1.2.1(3) of Attachment AE to add language that provides if a Market Participant does not provide an hourly baseline for a Demand Response Load, then the Transmission Provider shall set the hourly baseline equal to the Real-Time consumption of the Demand Response Resource associated with the Demand Response Resource in the Dispatch Interval immediately preceding initial commitment of the resource. The addition of this term is just and reasonable as it allows the Transmission Provider to fill in a hourly baseline if the Market Participant fails to provide one (as required in Section 4.1.2.1(3)(a)).[11] Therefore, the Transmission Provider will establish the hourly baseline based on actual consumption of the Demand Response Resource - a result which allows the Market Participant the benefit of a current hourly baseline that accurately reflects the customer's current usage.

3. *Clarification of Demand Bid and Demand Bid Curve Development*

SPP proposes to clarify the development of Demand Bids and the calculation of the Demand Bid Curve price in Section 4.3.1(4) of Attachment AE. A Demand Bid is the mechanism by which Market Participants voluntarily bid their loads into the Day-Ahead Market. The cleared load is used to determine the amount of generation to clear in the Day-Ahead Market. Out of this process the resources are committed out of the Day-Ahead Market for dispatch in the RTBM. A price sensitive Demand Bid is specified as a Demand Bid Curve.

Section 4.3.1.1(4) is being revised to provide that a price sensitive Demand Bid will clear "when (as opposed to the current "only if") the price at the applicable load Settlement Location is less than or equal to the specified Demand Bid Curve price for that Operating Hour. The proposed changes also provide clarification language of the maximum amount that can be cleared consistent with the addition of a minimum amount that can be cleared. Notably, the minimum amount that can be cleared is equal to zero. Without the clarification the minimum load value would be undefined, which may result in differing interpretations what minimum load value is acceptable for a Demand Bid. As this language is clarifying in nature, and does not substantively change the current practice of allowing minimum demand bidding of zero, the Commission should accept the proposed Tariff revisions to Section 4.3.1(4) of the Tariff as just and reasonable.

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11 *See* Tariff at Attachment AE, Section 4.1.2.1(3)(a).

4. *Clarification of Invoice Dispute Process*

With this filing, SPP proposes to revise Section 6.4.1.1 of Attachment AE to provide additional refinement to the rights and obligations of a Market Participant to receive or dispute an Uninstructed Resource Deviation ("URD") Exemption.[12] A Market Participant may receive an exemption from a URD if it meets the criteria of Section 6.4.1.1. The proposed modifications delete language that is unnecessary and/or potentially ambiguous to how a Market Participant may be granted an URD exemption. Additionally, SPP's proposed modifications provide more descriptive language regarding the URD exemption for force majeure events. SPP's proposed Tariff revisions also clarify the terms for dispute resolution if a Market Participant is not granted a URD exemption. The following revisions are being proposed to this section:

- Deletion of extraneous and/or potentially ambiguous introductory language

- Simplification of introductory language to succinctly state that a resource will receive a URD exemption in a Dispatch Interval under the conditions listed in the section

- Revise part (7) to more clearly identify situations that a URD may be granted by a force majeure event (pursuant to the meaning provided in Section 10.1 of the Tariff), or in the case of a Variable Energy Resource, high wind or other extreme weather related conditions that directly impacts the output

- Subject the Transmission Provider's actions under this section to the invoice dispute resolution provisions of Section 10.3 of Attachment AE. The proposed language retains the requirement that the Market Participant must provide adequate documentation and allows an audio file documenting the call between Market Participant and Transmission Provider to be counted as documentation. Delete the option for a plant operations log to be utilized as documentation.

The Commission should approve the revisions proposed to Section 6.4.1.1 of Attachment AE because the section will more accurately and succinctly state the

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[12] *See* Attachment AE, Section 1.1 Definitions U. An URD is defined as "[t]he Megawatt amount by which a Resource's actual output in a Dispatch Interval is above or below that Resource's average Setpoint Instruction in the Dispatch Interval." A URD may result in an additional charge to the Market Participant pursuant to Section 8.6.7 of Attachment AE.

rights and obligations of Market Participants to receive an URD exemption or dispute the Transmission Provider's decision to not grant an URD exemption.

5. *Transmission Service Verification for Specific Resources*

In this filing, SPP proposes that additional language be added to Section 7.1.1 of Attachment AE to establish a process to align transmission service sources to the appropriate granularity needed for the Integrated Marketplace. Pursuant to Section 7.1.1, the Transmission Provider must verify existing transmission service entitlements when determining Eligible Entities qualifications to receive candidate Auction Revenue Rights ("ARRs") in a particular time period. Section 7.1.1(1) provides the process to verify existing transmission entitlements for network service or firm Point-to-Point Transmission Service under the Tariff.[13] Under this provision, for a service reservation with a source inside the SPP Balancing Authority that is not a specific resource or resource market hub, the Transmission Provider will determine the settlement location that electrically corresponds to the source on the reservation that will be utilized for the candidate ARRs.[14] However, many transmission service reservations ("TSRs") on the SPP Open Access Same-time Information System ("OASIS") have a non-Resource specific source that is the functional equivalent of an aggregate load settlement location. A Market Participant's OASIS reservation for network service to serve its Network Load or Point-to-Point reservations to support third party sales are two examples of the type of TSR that would likely fall into this category.

The proposed language to Section 7.1.1(1)(a)(i) functionally provides that Eligible Entities may create resource specific TSRs that represent the Eligible Entities' current OASIS TSRs using the process described in the Market Protocols. Without such provisions, an Eligible Entity would not be able to leverage non-Resource specific transmission service to realize candidate ARRs. The purpose of the revisions are to provide in the Tariff an Eligible Entity's general right to utilize non-Resource specific TSRs for purposes of determining Settlement Locations and ultimate candidacy for potential awarding of ARRs. Commission approval of the proposed Tariff revisions would align the Tariff with the existing Market Protocols and is a just and reasonable outcome to allow Market Participants that have non-Resource specific TSRs to identify a Settlement Location for their transmission service and access full participation in the Integrated Marketplace.

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[13] *See* Tariff at Attachment AE, Section 7.1.1 (1).

[14] *See id.* at Section 7.1.1(1)(a)(i).

6. *Clarification of Process If Day-Ahead Market Solution Does Not Solve*

With this filing, SPP requests that Section 8.3(4) of Attachment AE be revised to include language recognizing that if the Day-Ahead Market does not solve for a given operating day, then the Locational Marginal Price ("LMP"), the Marginal Loss Component ("MLC"), and the Market Clearing Price ("MCP") for the purposes of calculating TCR settlement for the operating day shall be set to zero. Currently, the software coding sets the value of the Day-Ahead LMP, the MLC and MCP at "null." From a theoretical standpoint, setting the value to "null" and "zero" are synonymous. However, from a coding standpoint, the use of "null" is recognized at being synonymous with "not applicable," rather than the required value of zero. Therefore, the Tariff modification proposed herein clarifies that the coding will recognize the Day-Ahead LMP, MLC and MCP to be "zero" rather than "null" (i.e., "not applicable").

The proposed Tariff language ensures the Tariff and Market Protocols at Section 7.1.1 are consistent. This change is clarification only and does not represent a substantive change to the Tariff approved process SPP will utilize to calculate and settle TCRs in the event the Day-Ahead Market system fails. However, without the change, the values described herein would default to a load calculation share and result in a charge allocation to the Revenue Neutrality Uplift ("RNU"), rather than settlement utilizing the RTBM as currently provided in the approved Tariff.[15]

7. *Invoice Timing Requirements*

SPP proposes to modify Section 10.2 of Attachment AE with regards to the timing of payments by the Transmission Provider to Market Participants and vice versa. The proposed modifications will align the Tariff and Market Protocols related to the date payments are due. The changes include clarifying language to state that Market Participants have no later than 5:00 PM on the 4th business day after the invoice is issued to make payment to the Transmission Provider. Similarly, the Transmission Provider makes payments to Market Participants no later than 5:00 PM on the 6th business day following the day the invoice is issued. These two changes provide an extra day than what is currently provided in the Tariff. Commission approval of the timeline modification will allow the Tariff and Market Protocols to be internally consistent with regards to the payment obligations of both the Market Participant and the Transmission Provider. This outcome will increase transparency

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15 *See* Tariff at Attachment AE, Section 8.3(4) (providing that the TCR charge type shall continue to be settled as part of the Day-Ahead Market settlement using the MCC's calculated from the RTBM and congestion revenue collected as part of the RTBM settlement).

and mitigate any confusion that may exist regarding the proper date and time to make payment.

III. EFFECTIVE DATE

SPP requests that the Commission accept the proposed revisions to the Tariff to become effective September 8, 2014, which is not less than 60 days, or more than 120 days, after the submission of this filing as required by the Commission.[16]

IV. ADDITIONAL INFORMATION

A. Documents Submitted with this Filing:

In addition to this transmittal letter, the following documents are included with this filing:

Clean and Redline Tariff revisions under the Sixth Revised Volume No. 1

B. Service:

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

C. Requisite Agreement:

These revisions to the Tariff do not require any contracts or agreements.

D. Part 35.13 Cost of Service Support

The basis for the proposed Tariff revisions has been explained in this transmittal letter. The Commission's requirements for an estimate of transactions and revenues, and a comparison to rates for similar service are not applicable to the Tariff revisions being proposed herein. Further, no specifically assignable facilities are being installed or modified.

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16 *See* 18 C.F.R. § 35.3 at (a) (1).

E. Communications

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

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V. CONCLUSION

For all of the foregoing reasons, SPP respectfully requests that the Commission accept the Tariff revisions proposed herein as just and reasonable, with the effective date of September 8, 2014.

Respectfully submitted,

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1.1 Definitions C

CFTC

The Commodity Futures Trading Commission

Commercial Model

A representation of the attributes of and the relationships between Market Participants, Asset Owners, Resource and load assets and Price Nodes for use in the Integrated Marketplace.

Commercial Operation

As defined in Attachment V of this Tariff.

Commitment Instruction

An instruction issued by the Transmission Provider or a local transmission operator to a Market Participant to either start up or shut down a specified Resource in the Day-Ahead Market or any Reliability Unit Commitment process.

Commit Time

The time specified by the Transmission Provider or a local transmission operator in a Commitment Instruction at which a Resource is to be synchronized and operating at or above its Minimum Economic Capacity Operating Limit.

Common Bus

A single bus to which two or more Resources owned by the same Asset Owner are connected in an electrically equivalent manner where such Resources may be treated as interchangeable for certain compliance monitoring purposes.

Confidential Information

As referenced within Attachments AE, AF and AG to this Tariff, information containing or revealing:

(1) (a) Any confidential, proprietary, or commercially sensitive information, or information of a plan, specification, pattern, procedure, design, device, list,

concept, policy or compilation relating to the present or planned business of a Market Participant that is conspicuously designated as Confidential Information in writing, on each page of the document, by disclosing party at the time the information is provided to receiving party, whether conveyed electronically, in writing, through inspection, or otherwise;

(b) Any confidential, proprietary, or commercially sensitive information, or information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Market Participant that is provided orally and designated as Confidential Information by disclosing party at the time the information is provided to receiving party;

(c) Any customer information designated by the customer as proprietary, unless the customer has authorized the release for public disclosure of such information;

(d) Any software, products of software or other vendor information that the Transmission Provider is required to keep confidential under its agreements.

(2) Confidential Information does not include Critical Energy Infrastructure Information ("CEII") materials as designated by FERC, which must be obtained in accordance with FERC regulations.

Contingency Reserve

Qualified Resource capacity held in reserve for Resource contingencies that is the sum of Spinning Reserve and Supplemental Reserve.

Contingency Reserve Deployment Instruction

An instruction issued by the Transmission Provider to Resources cleared for Contingency Reserve in the Real-Time Balancing Market to deploy a specific Megawatt quantity of Contingency Reserve as communicated as a component of the Setpoint Instructions.

Contingency Reserve Deployment Period

The time allowed to deploy Contingency Reserve following the issuance of aContingency Reserve Deployment Instruction, as specified in theMarket Protocols.

Control Status

A parameter communicated electronically to the Transmission Provider by a Market Participant at any time during an Operating Hour indicating a Resource's ability to follow Setpoint Instructions.

Coordinated Flowgate

A flowgate defined within a joint operating agreement between the Transmission Provider and another transmission provider as being affected by the transmission of Energy on either party's transmission system.

Current Operating Plan

The Transmission Provider's internal hourly Resource commitment schedule for the Operating Day resulting from the Day-Ahead Market and Day-Ahead Reliability Unit Commitment processes and updated, as required, during the Intra-Day Reliability Unit Commitment process that is used as input into the Real-Time Balancing Market.

4.1.2 Additional Provisions for Non-Traditional Resources

4.1.2.1 Demand Response Resources

(1) Dispatchable Demand Response Resource - A Dispatchable Demand Response Resource is modeled in the Commercial Model the same as any other Resource, except that the Settlement Location associated with the Dispatchable Demand Response Resource must contain the Price Node, or aggregated Price Node as described in Section 2.2(2) of this Attachment AE, associated with the Demand Response Load. The Market Participant must submit the Real-Time value of the Demand Response Load to the Transmission Provider via telemetering that meets the technical requirements specified in the Market Protocols. A Dispatchable Demand Response Resource may select one of two options for reporting of the actual Dispatchable Demand Response Resource output:

(a) Submitted Resource production option:

The Dispatchable Demand Response Resource output is sent directly to the Transmission Provider by the Market Participant via telemetering for Real-Time operational purposes and the Meter Agent submits either five (5) minute or hourly actual output values to the Transmission Provider for use in settlements. The submitted Resource production option is only allowed for Demand Response Resources that are: (1) utilizing strictly Behind-The-Meter Generation to provide the response and are utilizing Real-Time metering capable of reporting both the Behind-The-Meter Generation output and the load; (2) Demand Response Resources where the Market Participant is offering the Resource under a retail tariff provision that includes near Real-Time measurement and verification terms that are compliant with the Business Practices for Measurement and Verification of Wholesale Electricity Demand Response of the North American Energy Standards Board, incorporated by reference in the Commission's Regulations, 18 C.F.R. § 38.2(a)(12); or (3) Demand Response Load utilizing near Real-Time measurement and verification capability that is compliant with the Business Practices for Measurement and Verification of Wholesale Electricity Demand Response of the North American Energy Standards Board, incorporated by reference in the Commission's Regulations, 18 C.F.R. § 38.2(a)(12).

(b) Calculated Resource production option:

(i) For each Dispatch Interval in each hour in which the Demand Response Resource has been committed, the Demand Response Resource output for Real-Time operational purposes is calculated by the Transmission Provider as the greater of zero (0) or the difference between:

- The lesser of the Real-Time consumption of the Demand Response Load associated with the Demand Response Resource in the Dispatch Interval immediately preceding initial commitment of the Demand Response Resource or the hourly baseline as described in (3) below for the hour, and
- The actual value of the associated Demand Response Load received via telemetering.

(ii) For each Dispatch Interval in each hour in which the Demand Response Resource has been committed, the Demand Response Resource output for settlement purposes is calculated by the Transmission Provider as the maximum of zero (0) or the difference between:

- The lesser of the Real-Time consumption of the Demand Response Load associated with the Demand Response Resource in the Dispatch Interval immediately preceding initial commitment of the Demand Response Resource or the hourly baseline as described in (3) below for the hour, and
- The actual value of the associated Demand Response Load received from the Meter Agent either on a five (5) minute basis or an hourly basis.

(2) Block Demand Response Resource – A Block Demand Response Resource is modeled in the Commercial Model the same as any other Resource except that the Settlement Location associated with the Block Demand Response Resource must contain the Price Node, or aggregated Price Node as described in Section 2.2(2) of this Attachment AE, associated with the Demand Response Load. The Market Participant must submit the Real-Time value of the Demand Response Load to the Transmission Provider via telemetering that meets the technical requirements specified in the Market Protocols. All Block Demand Response Resources will use the calculated Resource production option, described in Section 4.1.2.1(1)(b) above, to determine the amount of Real-Time Resource production and actual Resource production.

(a) If the Block Demand Response Resource is committed and dispatched in the Day-Ahead Market, Day-Ahead RUC or Intra-Day RUC, the Block Demand Response Resource's Minimum Economic Capacity Operating Limit will be increased in the RTBM to match the dispatched amount. Spinning Reserve or Supplemental Reserve will be allowed to clear above minimum output if the Block Demand Response Resource is a Spin Qualified Resource and Supplemental Reserve will be allowed to clear above minimum output if the Block Demand Response Resource is a Supplemental Qualified Resource.

(b) Spinning Reserve and/or Supplemental Reserve clearing will be based upon submitted ramp rates for the Block Demand Response Resource, the submitted Spinning Reserve Offer, the Supplemental Reserve Offer and the Block Demand Response Resource's Maximum Economic Capacity Operating Limit.

(3) Hourly Baseline

(a) The Market Participant must submit an hourly baseline for the Demand Response Load indicating the level of energy consumption expected at that location in MWh if the Demand Response Resource is not dispatched. The baseline must cover, at a minimum, all hours the Resource is submitting Offers for in the Energy and Operating Reserve Markets. This baseline must be submitted by 1100 hours on the day prior to the Operating Day and may be updated up to thirty (30) minutes in advance of the operating hour. The baseline should be based on the average of the hourly integrated Demand Response Load for the same hours in the last 30 calendar days when the Resource was not dispatched, adjusted by the Market Participant as necessary to account for changes in the expected level of energy consumption by the Demand Response Load.

(b) If there have been deviations in hourly integrated metered load from the hourly baseline during periods when the Resource was not dispatched the hourly baseline will be adjusted as follows by the Transmission Provider prior to the calculation of the Demand Response Load. If the average of the hourly deviation between integrated metered load and submitted hourly baseline for the hours in the last thirty (30) calendar days when the Resource was not dispatched is more than five percent (5%) below the hourly baseline, the hourly baseline will be adjusted by the average deviation. The Transmission Provider will perform this assessment each day and notify the Market Participant of any adjustment.

(c) If the hourly baseline has not been submitted, the Transmission Provider shall set the hourly baseline equal to the Real-Time comsumption of the Demand Response Load associated with the Demand Response Resource in the Dispatch Interval immediately preceding initial commitment of the Demand Response Resource.

4.1.2.2 Combined Cycle Resource

Market Participants shall select from one of the three following options regarding submitting Resource Offers for their registered combined cycle Resources, which will be declared during asset registration as described under Sections 2.2 and 2.9 of this Attachment AE:

(1) A Resource Offer may be submitted for a single aggregate combined cycle Resource, where the aggregate will represent a Market Participant selected operating configuration of combustion turbines and steam turbines. Under

this option, the combined cycle Resource will be committed, dispatched and settled the same as any other Resource; or

(2) A Resource Offer may be submitted for each combined cycle Resource combustion turbine and/or steam turbine and each component will be committed and dispatched independently and settled the same as any other single Resource; or

(3) A Resource Offer may be submitted for each pseudo combined cycle Resource, where each pseudo combined cycle Resource will represent the combination of one combustion turbine and a portion of the steam turbine. Under this option, each pseudo combined cycle Resource must be capable of being committed and dispatched independently the same as any other Resource and each pseudo combined cycle Resource will be settled the same as any other Resource.

4.1.2.3 Jointly Owned Unit

Each Market Participant may submit Resource Offers for its share of the Jointly Owned Unit as specified in the Market Protocols. Offer parameters must meet the following criteria in order to be accepted as valid Offers, otherwise the last submitted valid offer shall apply:

(1) The sum of the Maximum Emergency Capacity Operating Limits of all shares of the Jointly Owned Unit must be less than or equal to the Jointly Owned Unit maximum physical capacity operating limit; and

(2) The sum of the Minimum Emergency Capacity Operating Limits of all shares of the Jointly Owned Unit must be greater than or equal to the Jointly Owned Unit minimum physical capacity operating limit.

Commitment of individual Jointly Owned Unit shares that have registered under the individual Resource option will be evaluated by security constrained unit commitment ("SCUC") based on the individually submitted Offers for each Jointly Owned Unit share.

Commitment of Jointly Owned Unit shares that have registered under the combined Resource option will be evaluated by SCUC based on a combination of the individually submitted Offers for each Jointly Owned Unit share and the commitment related Offer parameters submitted by the designated Market Participant that apply to the entire Jointly Owned Unit given the additional constraint that if one of the Jointly Owned Units is committed, all Resource shares for each Jointly Owned Unit must be committed. This rule also applies to clearing of Supplemental Reserve from off-line Quick-Start Resources.

4.1.2.4 Dispatchable Variable Energy Resource

Each Market Participant may submit Resource Offers for Dispatchable Variable Energy Resources using the same Offer parameters available to any other Resource, except that:

(1) The minimum operating limits specified in the Resource Offer must be equal to zero;

(2) The maximum operating limits for use in the Day-Ahead RUC and the Intra-Day RUC shall be calculated by the Transmission Provider as equal to the lesser of the maximum operating limits submitted in the Resource Offer or the Transmission Provider's output forecast for that Resource to the extent that such output forecast is available;

a) Dispatchable Variable Energy Resources for which the Transmission Provider is calculating an output forecast are not eligible to receive RUC make whole payments as described under Section 8.6.5 of this Attachment AE.

(3) For the purposes of issuing Dispatch Instructions to Resources as described under Section 4.1.2.4(6) of this Attachment AE, Dispatchable Variable Energy Resources with a maximum capability of less than two-hundred (200) MWs, submitted ramp rates multiplied by five (5) cannot exceed forty (40) MWs;

(4) For the purposes of issuing Dispatch Instructions to Resources as described under Section 4.1.2.4(6) of this Attachment AE, Dispatchable Variable Energy Resources with a maximum capability of greater than or

equal to two-hundred (200) MWs, submitted ramp rates multiplied by five (5) cannot exceed twenty percent (20%) of the maximum capability;

(5) For the RTBM, during times when the Transmission Provider issues a Dispatch Instruction to a Dispatchable Variable Energy Resource to reduce output, the Resource's Setpoint Instruction shall be equal to the sum of the Resource's Dispatch Instruction and any Regulation-Down deployment, even if the Market Participant has indicated that the Resource is not dispatchable;

(6) For the RTBM, during times when the Transmission Provider issues a Dispatch Instruction to a Dispatchable Variable Energy Resource to increase output in Dispatch Intervals immediately following a Dispatch Interval in which a Dispatch Instruction was issued to reduce output as described in Section 4.1.2.4(5) of this Attachment AE, the Transmission Provider shall calculate the Resource maximum operating limit to be equal to:

(a) The lesser of the maximum operating limits submitted in the Resource Offer or the Transmission Provider's Dispatchable Variable Energy Resource output forecast for that Resource to the extent the such forecast is available, except that, the Transmission Provider's output forecast for the Resource shall be used for the maximum operating limits when: (i) maximum operating limits have not been submitted; (ii) the maximum operating limits submitted in the Resource Offer are more than thirty (30) minutes old; or (iii) the maximum operating limits submitted in the Resource Offer exceed the maximum physical rating of the Resource as stated during market registration; or

(b) The maximum operating limits submitted in the Resource Offer if the Transmission Provider's Dispatchable Variable Energy Resource output forecast for that Resource is not available.

The Transmission Provider shall continue to calculate such maximum operating limits for each subsequent Dispatch Interval until the maximum operating limit is equal to the lesser of the Transmission Provider's Dispatchable Variable Energy Resource output forecast for that Resource or the maximum operating limit submitted in the Resource Offer, after which, the Dispatchable Variable Energy Resource's maximum operating limit shall be calculated as described in Section 4.1.2.4(7) of this Attachment AE.

(7) For the RTBM, during times other than those times described under Section 4.1.2.4(6) of this Attachment AE, the Resource's maximum operating limit for use in the current Dispatch Interval shall be equal to the Resource's actual output at the start of the Dispatch Interval and the ramping restrictions described under Sections 4.1.2.4(3) and (4) of this Attachment AE shall not apply.

4.1.2.5 Non-Dispatchable Variable Energy Resource

Each Market Participant may submit Resource Offers for Non-Dispatchable Variable Energy Resources using the same Offer parameters available to any other Resource, except that

(1) For the RTBM, the Resource's Energy Offer Curve shall not apply;

(2) For the RTBM, the Resource's Dispatch Instruction shall be equal to the Resource's actual output at the start of the Dispatch Interval and the Resources must operate as non-dispatchable;

(3) Resource Energy Offer Curve prices shall be assumed equal to zero (0) for the purposes of calculating production costs relating to RUC make whole payments and cost allocation thereof under Sections 8.6.5 and 8.6.7 of this Attachment AE;

(4) For the RTBM, during times when it is necessary to issue a Manual Dispatch Instruction to a Non-Dispatchable Variable Energy Resource to resolve an Emergency Condition or reliability issue, the Transmission Provider will direct the Resource to a specified MW output. In addition,

the Transmission Provider will issue the dispatch instruction to the Resource in accordance with Section 6.2.4 of this Attachment AE; and

(5) The maximum operating limits for use in the Day-Ahead RUC and the Intra-Day RUC shall be calculated by the Transmission Provider as equal to the lesser of the maximum operating limits submitted in the Resource Offer or the Transmission Provider's output forecast for that Resource to the extent that such output forecast is available, otherwise the maximum operating limits shall be equal to those submitted in the Resource Offer;

(a) Non-Dispatchable Variable Energy Resources for which the Transmission Provider is calculating an output forecast are not eligible to receive RUC make whole payments as described under Section 8.6.5 of this Attachment AE.

4.1.2.6 External Dynamic Resource

Each Market Participant may submit Resource Offers for External Dynamic Resources ("EDR") using the same Offer parameters available to any other Resource, except that:

(1) A Market Participant may only submit a commitment status as defined in Section 4.1(10)(a) or (d) of this Attachment AE;

(2) For an EDR in the Eastern Interconnection, a Market Participant must submit a dispatch status indicating that the EDR is not available for energy dispatch as described under Section 4.1(11)(a) of this Attachment AE;

(3) For an EDR in the Eastern Interconnection, Resource Offer parameters are limited to: Regulation-Up and Regulation-Down Offers, Spinning and Supplemental Reserve Offers, Regulation Ramp Rate, Contingency Reserve Ramp Rate and Resource Status. All other Resource Offer parameters as listed in Section 4.1(9) of this Attachment AE shall not apply to EDRs in the Eastern Interconnection.

(4) For an EDR that is not in the Eastern Interconnection, Resource Offer parameters are limited to: Energy Offer Curve, Ramp-Rate-Up, Ramp-Rate-Down, Regulation-Up and Regulation-Down Offers, Spinning and

Supplemental Reserve Offers, Regulation Ramp Rate, Contingency Reserve Ramp Rate and Resource Status. All other Resource Offer parameters as listed in Section 4.1(9) of this Attachment AE shall not apply to EDRs that are not in the Eastern Interconnection.

4.3.1 Demand Bids

(1) Only Market Participants with registered physical load assets may submit Demand Bids for use in the Day-Ahead Market.

(2) A Market Participant can submit Demand Bids only at Settlement Locations where its physical load assets are registered.

(3) A Market Participant is not permitted to submit a Demand Bid for a load asset pseudo-tied out of the SPP Balancing Authority.

(*4*) A fixed Demand Bid is a specified MW that will be cleared in the Day-Ahead Market regardless of the price at the load Settlement Location based on the start and stop time submitted for the applicable Operating Day.

(*5*) A price sensitive Demand Bid is specified as a Demand Bid Curve. A price sensitive Demand Bid will clear when the price at the applicable load Settlement Location is less than or equal to the specified Demand Bid Curve price for that Operating Hour.The maximum MW amount that can be cleared is equal to the highest Megawatt quantity submitted in the Demand Bid Curve . The minimum MW amount that can be cleared is equal to zero.

6.4.1 Uninstructed Resource Deviation

The following rules apply to the calculation of Uninstructed Resource Deviation ("URD").

(1) *For the purposes of determining URD exemptions for Resources that are part of a Common Bus as described under Section 6.4.1.1(6) of this Attachment AE, each Asset Owner's* Resources' combined average ramped MW Setpoint Instruction and combined actual average MW output at the Common Bus will be used *to calculate* URD *at the Common Bus* for the Dispatch Interval *for each Asset Owner*.

(2) A Resource's URD is allocated a portion of the RUC make whole payment costs, as described under Section 8.6.7 of this Attachment AE, in any Dispatch Interval where Resource's URD is outside of its Operating Tolerance unless that Resource has been exempted from URD.

  (a) A generating unit Resource's Operating Tolerance in each Dispatch Interval is equal to the Resource's Maximum Emergency Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

  (b) A Dispatchable Demand Response Resource's Operating Tolerance in each Dispatch Interval is equal to the resource's Maximum Emergency Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

  (c) A Block Demand Response Resource's Operating Tolerance in each Dispatch Interval is equal to the resource's Maximum Economic Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

  (d) The Common Bus Operating Tolerance for each Market Participant registered at a Common Bus is equal to the sum of that Market Participant's Resources' Maximum Emergency Capacity Operating Limits for Resources that are on-line multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(e) If the absolute value of a Resource's URD is greater than the Resource's Operating Tolerance in any Dispatch Interval, the Resource URD / 12 is included in the hourly allocation of RUC make whole payment cost allocation. The Hourly URD amount is calculated as the sum of Dispatch Interval URD for the hour. Additionally, if that Resource was eligible to receive a RUC make whole payment, the payment may be reduced in accordance with Section 8.6.5 of this Attachment AE.

6.4.1.1 Uninstructed Resource Deviation Exemptions

A Resource will receive a URD exemption in a Dispatch Interval under the following situations:

(1) The Resource is deployed for Contingency Reserve *as described in Section 6.3.2 of this Attachment AE or is deployed for a Contingency Reserve test as described under Sections 2.10.1 and 2.10.2 of this Attachment AE*; or

(2) The Resource trips off-line or is derated after receiving Dispatch Instructions; or

(3) There is missing or bad Resource SCADA data in the Dispatch Interval; or

(4) If during Emergency Conditions the URD is *due to a Resource output* above the Resource's Setpoint Instruction in a shortage condition or the URD is *due to a Resource output* below the Resource's Setpoint Instruction during an excess generation condition; or

(5) If a Dispatch Instruction is issued to a Resource beyond the reported capabilities due to the application of a VRL; or

(6) If the Resource is part of a Common Bus and the URD calculated at the Common Bus is less than the Operating Tolerance calculated at the Common Bus; or

(7) If the URD results from an event of force majeure or, in the case of a Variable Energy Resource, if the URD results from extremely high wind or other extreme weather-related conditions materially and directly impacting a Variable Energy Resource's ability to provide or reduce output of Energy. For purposes of this subsection, the term force majeure shall have the meaning described under Section 10.1 of this Tariff except that acts of Curtailment shall not qualify for exemption. ; or

(8) If the Resource has been issued a Manual Dispatch Instruction.

In the event a Resource does not receive a URD exemption in a Dispatch Interval, the Transmission Provider shall determine through the dispute process, in accordance with the invoice dispute process as provided in Section 10.3 of this Attachment AE, whether an exemption to an Uninstructed Resource Deviation will be given. The Market Participant may provide the Transmission Provider with adequate documentation in order for the Market Participant to be eligible to avoid such Uninstructed Resource Deviation. Adequate documentation may include but is not limited to an audio file documenting a call between the Market Participant and the Transmission Provider.

6.4.1.2 Load Deviation Exemptions

A load is exempt from deviation based charges for cost allocation under Section 8.6.7 under the following situations:

(1) The RTBM billable metering for load is less than that load's Day-Ahead Market cleared quantity during a capacity shortage condition Emergency.

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. 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. Eligible Entities may create Resource specific Transmission Service reservations that represent their current Transmission Service reservations using the process described in the Market Protocols.

(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.

8.3 Calculation of Locational Marginal Prices, Locational Marginal Price Components, and Market Clearing Prices

An LMP shall be calculated for each Meter Settlement Location for the Day-Ahead Market and RTBM and shall be calculated as the price at that location based on the SCED and Operating Reserve clearing, the Dispatchable Resource Energy Offer Curve, Operating Reserve Offer prices and Resource characteristics submitted by Market Participants and data from the State Estimator. The following rules will be used in calculating the LMPs:

(1) LMPs are calculated by the Transmission Provider for each hour in the Day-Ahead Market and each Dispatch Interval in the RTBM as part of the SCED solution described under Section 6.2.2 of this Attachment AE. In performing these calculations, Dispatchable Resources will be eligible to set the LMP under the following conditions:

(a) The Dispatchable Resource must be operating below its maximum capacity limit;

(b) The Dispatchable Resource must be operating above its minimum capacity limit; and

(c) The Dispatchable Resource output must not be ramp rate constrained such that the Dispatchable Resource cannot achieve the optimal desired dispatch point under the economic dispatch.

(2) The Transmission Provider shall calculate LMPs, MCCs and MLCs for use in settlement as follows:

(a) An LMP, MCC and MLC shall be calculated for each Meter Settlement Location for each hour in the Day-Ahead Market and for every Dispatch Interval in the RTBM.

(b) The LMP, MCC and MLC for a load Settlement Location or a Demand Response Load location with multiple Meter Settlement Locations for an hour within the Day-Ahead Market or a Dispatch Interval within the RTBM shall be equal to the load weighted average of LMPs calculated for Meter Settlement Locations aggregated to that Settlement Location or Demand Response Load location for that hour or Dispatch Interval. The load weights utilized in this calculation for the Day-Ahead Market shall be based upon a historical Real-Time load calculated at each Meter Settlement Location by the State Estimator and for the RTBM shall be based upon the actual Real-Time load calculated at each Meter Settlement Location by the State Estimator in that Dispatch Interval.

(c) The LMP, MCC and MLC for a Resource Settlement Location for an hour in the Day-Ahead Market and for a Dispatch Interval in the RTBM shall equal the LMP, MCC and MLC calculated for that Settlement Location for the Resource or, in the case of a Block Demand Response Resource, the LMP, MCC and MLC calculated at the associated Demand Response Load location.

(d) The LMP, MCC and MLC for a Market Hub Settlement Location for an hour within the Day-Ahead Market or a Dispatch Interval within the RTBM shall be equal to the weighted average of LMPs, MCCs and MLCs calculated for Price Nodes within the Market Hub aggregated to that Market Hub Settlement Location for that hour or Dispatch Interval. The weights utilized in this calculation for the Day-Ahead Market shall be determined by the Transmission Provider, in consultation with Market Participants, at the time the Market Hub is created.

(e) The LMP, MCC and MLC for an External Interface Settlement Location for an hour within the Day-Ahead Market or a Dispatch Interval within the RTBM shall be equal to the weighted average of LMPs, MCCs and MLCs calculated for Price Nodes within the External Interface aggregated to that External Interface Settlement Location for that hour or Dispatch Interval. The weights utilized in this calculation for the Day-Ahead Market and RTBM shall be determined by the Transmission Provider at the time the External Interface is created.

(3) If there is insufficient capacity to meet the Energy requirements on a system-wide basis, Energy requirements are reduced to meet available capacity and LMPs are calculated as described under Section 8.3.1.

(4) In the event a failure of the Day-Ahead Market systems results in the loss of the ability to clear the Day-Ahead Market in a timely manner, the TCR charge type described under Section 8.5.11 shall continue to be settled as part of the Day-Ahead Market settlement using the MCCs calculated for the corresponding Operating Day for the RTBM and the congestion revenue collected as part of the RTBM settlement. TCR uplift calculated under Section 8.5.12 shall be set equal to zero and the differences between amounts paid under Section 8.5.11 and available real-time congestion revenue shall be accounted for under Section 8.8. In the event a failure of the Day-Ahead Market systems results in the loss of the ability to clear the Day-Ahead Market, the Transmission Provider will set the Day-Ahead Market LMP, MLC, and MCP to zero.

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

(a) If the failure of the RTBM systems occurs for twelve (12) Dispatch Intervals or less, the estimated LMPs and LMP components shall be the most recently calculated LMPs, MCCs, and MLCs for each affected Settlement Location and shall be utilized for settlement purposes for each of the Dispatch Intervals in which LMP pricing data is missing.

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

(6) If for any reason a portion of generation and load within the SPP Balancing Authority Area becomes isolated from the rest of the SPP Balancing Authority Area ("Island"), the Transmission Provider shall calculate LMPs, MCCs, and MLCs for the RTBM within the Island using mitigated Offers for Resources within the Island in a manner that reflects, as closely as practicable, the LMPs, MCCs, and MLCs within the Island that would have resulted as if the RTBM systems had calculated the values, and shall use such LMPs, MCCs, and MLCs for settlement purposes within the Island for each of the Dispatch Intervals.

10.2 Invoices

(1) The Transmission Provider shall issue an invoice detailing all charges and payments specified in Section 8 of this Attachment AE on a weekly basis in accordance with the invoice issue dates specified in the Market Protocols.

(2) The Transmission Provider shall make payments to the Market Participant for any net credit shown on the invoice and the Market Participant shall make payment to the Transmission Provider for any net charge shown or the invoice, including disputed amounts. Resolution of disputed amounts shall be shown as an adjustment on future invoices.

(3) Market Participants shall make payment to the Transmission Provider that is equal to the net charge shown on the invoice by no later than 5:00 PM on the 4th business day following the day the invoice was issued.

(4) The Transmission Provider shall make payment to the Market Participant that is equal to the net credit shown on the invoice by no later than 5:00 PM on the 6th business day following the day the invoice was issued subject to the procedures specified under Section V of Attachment L.

(5) All payments to the Market Participant and all payments to the Transmission Provider shall be made by electronic funds transfer in U.S. dollars.

1.1 Definitions C

CFTC

The Commodity Futures Trading Commission

Commercial Model

A representation of the attributes of and the relationships between Market Participants, Asset Owners, Resource and load assets and Price Nodes for use in the Integrated Marketplace.

Commercial Operation

As defined in Attachment V of this Tariff.

Commitment Instruction

An instruction issued by the Transmission Provider or a local transmission operator to a Market Participant to either start up or shut down a specified Resource in the Day-Ahead Market or any Reliability Unit Commitment process.

Commit Time

The time specified by the Transmission Provider or a local transmission operator in a Commitment Instruction at which a Resource is to be synchronized and operating at or above its Minimum Economic Capacity Operating Limit.

Common Bus

A single bus to which two or more Resources owned by the same Asset Owner are connected in an electrically equivalent manner where such Resources may be treated as interchangeable for certain compliance monitoring purposes.

Confidential Information

As referenced within Attachments AE, AF and AG to this Tariff, information containing or revealing:

(1) (a) Any confidential, proprietary, or commercially sensitive information, or information of a plan, specification, pattern, procedure, design, device, list,

concept, policy or compilation relating to the present or planned business of a Market Participant that is conspicuously designated as Confidential Information in writing, on each page of the document, by disclosing party at the time the information is provided to receiving party, whether conveyed electronically, in writing, through inspection, or otherwise;

(b) Any confidential, proprietary, or commercially sensitive information, or information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Market Participant that is provided orally and designated as Confidential Information by disclosing party at the time the information is provided to receiving party;

(c) Any customer information designated by the customer as proprietary, unless the customer has authorized the release for public disclosure of such information;

(d) Any software, products of software or other vendor information that the Transmission Provider is required to keep confidential under its agreements.

(2) Confidential Information does not include Critical Energy Infrastructure Information ("CEII") materials as designated by FERC, which must be obtained in accordance with FERC regulations.

Contingency Reserve

Qualified Resource capacity held in reserve for Resource contingencies that is the sum of Spinning Reserve and Supplemental Reserve.

Contingency Reserve Deployment Instruction

An instruction issued by the Transmission Provider to Resources cleared for Contingency Reserve in the Real-Time Balancing Market to deploy a specific Megawatt quantity of Contingency Reserve as communicated as a component of the Setpoint Instructions.

Contingency Reserve Deployment Period

The time allowed to deploy Contingency Reserve following the issuance of a ~~reserve sharing event~~Contingency Reserve Deployment Instruction, as specified in the ~~SPP Criteria~~Market Protocols.

Control Status

A parameter communicated electronically to the Transmission Provider by a Market Participant at any time during an Operating Hour indicating a Resource's ability to follow Setpoint Instructions.

Coordinated Flowgate

A flowgate defined within a joint operating agreement between the Transmission Provider and another transmission provider as being affected by the transmission of Energy on either party's transmission system.

Current Operating Plan

The Transmission Provider's internal hourly Resource commitment schedule for the Operating Day resulting from the Day-Ahead Market and Day-Ahead Reliability Unit Commitment processes and updated, as required, during the Intra-Day Reliability Unit Commitment process that is used as input into the Real-Time Balancing Market.

4.1.2 Additional Provisions for Non-Traditional Resources

4.1.2.1 Demand Response Resources

(1) Dispatchable Demand Response Resource - A Dispatchable Demand Response Resource is modeled in the Commercial Model the same as any other Resource, except that the Settlement Location associated with the Dispatchable Demand Response Resource must contain the Price Node, or aggregated Price Node as described in Section 2.2(2) of this Attachment AE, associated with the Demand Response Load. The Market Participant must submit the Real-Time value of the Demand Response Load to the Transmission Provider via telemetering that meets the technical requirements specified in the Market Protocols. A Dispatchable Demand Response Resource may select one of two options for reporting of the actual Dispatchable Demand Response Resource output:

(a) Submitted Resource production option:

The Dispatchable Demand Response Resource output is sent directly to the Transmission Provider by the Market Participant via telemetering for Real-Time operational purposes and the Meter Agent submits either five (5) minute or hourly actual output values to the Transmission Provider for use in settlements. The submitted Resource production option is only allowed for Demand Response Resources that are: (1) utilizing strictly Behind-The-Meter Generation to provide the response and are utilizing Real-Time metering capable of reporting both the Behind-The-Meter Generation output and the load; (2) Demand Response Resources where the Market Participant is offering the Resource under a retail tariff provision that includes near Real-Time measurement and verification terms that are compliant with the Business Practices for Measurement and Verification of Wholesale Electricity Demand Response of the North American Energy Standards Board, incorporated by reference in the Commission's Regulations, 18 C.F.R. § 38.2(a)(12); or (3) Demand Response Load utilizing near Real-Time measurement and verification capability that is compliant with the Business Practices for Measurement and Verification of Wholesale Electricity Demand Response of the North American Energy Standards Board, incorporated by reference in the Commission's Regulations, 18 C.F.R. § 38.2(a)(12).

(b) Calculated Resource production option:

(i) For each Dispatch Interval in each hour in which the Demand Response Resource has been committed, the Demand Response Resource output for Real-Time operational purposes is calculated by the Transmission Provider as the greater of zero (0) or the difference between:

- The lesser of the Real-Time consumption of the Demand Response Load associated with the Demand Response Resource in the Dispatch Interval immediately preceding initial commitment~~deployment~~ of the Demand Response Resource or the hourly baseline as described in (3) below for the hour, and
- The actual value of the associated Demand Response Load received via telemetering.

(ii) For each Dispatch Interval in each hour in which the Demand Response Resource has been committed, the Demand Response Resource output for settlement purposes is calculated by the Transmission Provider as the maximum of zero (0) or the difference between:

- The lesser of the Real-Time consumption of the Demand Response Load associated with the Demand Response Resource in the Dispatch Interval immediately preceding initial commitment~~deployment~~ of the Demand Response Resource or the hourly baseline as described in (3) below for the hour, and
- The actual value of the associated Demand Response Load received from the Meter Agent either on a five (5) minute basis or an hourly basis.

(2) Block Demand Response Resource – A Block Demand Response Resource is modeled in the Commercial Model the same as any other Resource except that the Settlement Location associated with the Block Demand Response Resource must contain the Price Node, or aggregated Price Node as described in Section 2.2(2) of this Attachment AE, associated with the Demand Response Load. The Market Participant must submit the Real-Time value of the Demand Response Load to the Transmission Provider via telemetering that meets the technical requirements specified in the Market Protocols. All Block Demand Response Resources will use the calculated Resource production option, described in Section 4.1.2.1(1)(b) above, to determine the amount of Real-Time Resource production and actual Resource production.

(a) If the Block Demand Response Resource is committed and dispatched in the Day-Ahead Market, Day-Ahead RUC or Intra-Day RUC, the Block Demand Response Resource's Minimum Economic Capacity Operating Limit will be increased in the RTBM to match the dispatched amount. Spinning Reserve or Supplemental Reserve will be allowed to clear above minimum output if the Block Demand Response Resource is a Spin Qualified Resource and Supplemental Reserve will be allowed to clear above minimum output if the Block Demand Response Resource is a Supplemental Qualified Resource.

(b) Spinning Reserve and/or Supplemental Reserve clearing will be based upon submitted ramp rates for the Block Demand Response Resource, the submitted Spinning Reserve Offer, the Supplemental Reserve Offer and the Block Demand Response Resource's Maximum Economic Capacity Operating Limit.

(3) Hourly Baseline

(a) The Market Participant must submit an hourly baseline for the Demand Response Load indicating the level of energy consumption expected at that location in MWh if the Demand Response Resource is not dispatched. The baseline must cover, at a minimum, all hours the Resource is submitting Offers for in the Energy and Operating Reserve Markets. This baseline must be submitted by 1100 hours on the day prior to the Operating Day and may be updated up to thirty (30) minutes in advance of the operating hour. The baseline should be based on the average of the hourly integrated Demand Response Load for the same hours in the last 30 calendar days when the Resource was not dispatched, adjusted by the Market Participant as necessary to account for changes in the expected level of energy consumption by the Demand Response Load.

(b) If there have been deviations in hourly integrated metered load from the hourly baseline during periods when the Resource was not dispatched the hourly baseline will be adjusted as follows by the Transmission Provider prior to the calculation of the Demand Response Load. If the average of the hourly deviation between integrated metered load and submitted hourly baseline for the hours in the last thirty (30) calendar days when the Resource was not dispatched is more than five percent (5%) below the hourly baseline, the hourly baseline will be adjusted by the average deviation. The Transmission Provider will perform this assessment each day and notify the Market Participant of any adjustment.

(c) If the hourly baseline has not been submitted, the Transmission Provider shall set the hourly baseline equal to the Real-Time comsumption of the Demand Response Load associated with the Demand Response Resource in the Dispatch Interval immediately preceding initial commitment of the Demand Response Resource.

4.1.2.2 Combined Cycle Resource

Market Participants shall select from one of the three following options regarding submitting Resource Offers for their registered combined cycle Resources, which will be declared during asset registration as described under Sections 2.2 and 2.9 of this Attachment AE:

(1) A Resource Offer may be submitted for a single aggregate combined cycle Resource, where the aggregate will represent a Market Participant selected operating configuration of combustion turbines and steam turbines. Under

this option, the combined cycle Resource will be committed, dispatched and settled the same as any other Resource; or

(2) A Resource Offer may be submitted for each combined cycle Resource combustion turbine and/or steam turbine and each component will be committed and dispatched independently and settled the same as any other single Resource; or

(3) A Resource Offer may be submitted for each pseudo combined cycle Resource, where each pseudo combined cycle Resource will represent the combination of one combustion turbine and a portion of the steam turbine. Under this option, each pseudo combined cycle Resource must be capable of being committed and dispatched independently the same as any other Resource and each pseudo combined cycle Resource will be settled the same as any other Resource.

4.1.2.3 Jointly Owned Unit

Each Market Participant may submit Resource Offers for its share of the Jointly Owned Unit as specified in the Market Protocols. Offer parameters must meet the following criteria in order to be accepted as valid Offers, otherwise the last submitted valid offer shall apply:

(1) The sum of the Maximum Emergency Capacity Operating Limits of all shares of the Jointly Owned Unit must be less than or equal to the Jointly Owned Unit maximum physical capacity operating limit; and

(2) The sum of the Minimum Emergency Capacity Operating Limits of all shares of the Jointly Owned Unit must be greater than or equal to the Jointly Owned Unit minimum physical capacity operating limit.

Commitment of individual Jointly Owned Unit shares that have registered under the individual Resource option will be evaluated by security constrained unit commitment ("SCUC") based on the individually submitted Offers for each Jointly Owned Unit share.

Commitment of Jointly Owned Unit shares that have registered under the combined Resource option will be evaluated by SCUC based on a combination of the individually submitted Offers for each Jointly Owned Unit share and the commitment related Offer parameters submitted by the designated Market Participant that apply to the entire Jointly Owned Unit given the additional constraint that if one of the Jointly Owned Units is committed, all Resource shares for each Jointly Owned Unit must be committed. This rule also applies to clearing of Supplemental Reserve from off-line Quick-Start Resources.

4.1.2.4 Dispatchable Variable Energy Resource

Each Market Participant may submit Resource Offers for Dispatchable Variable Energy Resources using the same Offer parameters available to any other Resource, except that:

(1) The minimum operating limits specified in the Resource Offer must be equal to zero;

(2) The maximum operating limits for use in the Day-Ahead RUC and the Intra-Day RUC shall be calculated by the Transmission Provider as equal to the lesser of the maximum operating limits submitted in the Resource Offer or the Transmission Provider's output forecast for that Resource to the extent that such output forecast is available;

  a) Dispatchable Variable Energy Resources for which the Transmission Provider is calculating an output forecast are not eligible to receive RUC make whole payments as described under Section 8.6.5 of this Attachment AE.

(3) For the purposes of issuing Dispatch Instructions to Resources as described under Section 4.1.2.4(6) of this Attachment AE, Dispatchable Variable Energy Resources with a maximum capability of less than two-hundred (200) MWs, submitted ramp rates multiplied by five (5) cannot exceed forty (40) MWs;

(4) For the purposes of issuing Dispatch Instructions to Resources as described under Section 4.1.2.4(6) of this Attachment AE, Dispatchable Variable Energy Resources with a maximum capability of greater than or

equal to two-hundred (200) MWs, submitted ramp rates multiplied by five (5) cannot exceed twenty percent (20%) of the maximum capability;

(5) For the RTBM, during times when the Transmission Provider issues a Dispatch Instruction to a Dispatchable Variable Energy Resource to reduce output, the Resource's Setpoint Instruction shall be equal to the sum of the Resource's Dispatch Instruction and any Regulation-Down deployment, even if the Market Participant has indicated that the Resource is not dispatchable;

(6) For the RTBM, during times when the Transmission Provider issues a Dispatch Instruction to a Dispatchable Variable Energy Resource to increase output in Dispatch Intervals immediately following a Dispatch Interval in which a Dispatch Instruction was issued to reduce output as described in Section 4.1.2.4(5) of this Attachment AE, the Transmission Provider shall calculate the Resource maximum operating limit to be equal to:

(a) The lesser of the maximum operating limits submitted in the Resource Offer or the Transmission Provider's Dispatchable Variable Energy Resource output forecast for that Resource to the extent the such forecast is available, except that, the Transmission Provider's output forecast for the Resource shall be used for the maximum operating limits when: (i) maximum operating limits have not been submitted; (ii) the maximum operating limits submitted in the Resource Offer are more than thirty (30) minutes old; or (iii) the maximum operating limits submitted in the Resource Offer exceed the maximum physical rating of the Resource as stated during market registration; or

(b) The maximum operating limits submitted in the Resource Offer if the Transmission Provider's Dispatchable Variable Energy Resource output forecast for that Resource is not available.

The Transmission Provider shall continue to calculate such maximum operating limits for each subsequent Dispatch Interval until the maximum operating limit is equal to the lesser of the Transmission Provider's Dispatchable Variable Energy Resource output forecast for that Resource or the maximum operating limit submitted in the Resource Offer, after which, the Dispatchable Variable Energy Resource's maximum operating limit shall be calculated as described in Section 4.1.2.4(7) of this Attachment AE.

(7) For the RTBM, during times other than those times described under Section 4.1.2.4(6) of this Attachment AE, the Resource's maximum operating limit for use in the current Dispatch Interval shall be equal to the Resource's actual output at the start of the Dispatch Interval and the ramping restrictions described under Sections 4.1.2.4(3) and (4) of this Attachment AE shall not apply.

4.1.2.5 Non-Dispatchable Variable Energy Resource

Each Market Participant may submit Resource Offers for Non-Dispatchable Variable Energy Resources using the same Offer parameters available to any other Resource, except that

(1) For the RTBM, the Resource's Energy Offer Curve shall not apply;

(2) For the RTBM, the Resource's Dispatch Instruction shall be equal to the Resource's actual output at the start of the Dispatch Interval and the Resources must operate as non-dispatchable;

(3) Resource Energy Offer Curve prices shall be assumed equal to zero (0) for the purposes of calculating production costs relating to RUC make whole payments and cost allocation thereof under Sections 8.6.5 and 8.6.7 of this Attachment AE;

(4) For the RTBM, during times when it is necessary to issue a Manual Dispatch Instruction to a Non-Dispatchable Variable Energy Resource to resolve an Emergency Condition or reliability issue, the Transmission Provider will direct the Resource to a specified MW output. In addition,

the Transmission Provider will issue the dispatch instruction to the Resource in accordance with Section 6.2.4 of this Attachment AE; and

(5) The maximum operating limits for use in the Day-Ahead RUC and the Intra-Day RUC shall be calculated by the Transmission Provider as equal to the lesser of the maximum operating limits submitted in the Resource Offer or the Transmission Provider's output forecast for that Resource to the extent that such output forecast is available, otherwise the maximum operating limits shall be equal to those submitted in the Resource Offer;

(a) Non-Dispatchable Variable Energy Resources for which the Transmission Provider is calculating an output forecast are not eligible to receive RUC make whole payments as described under Section 8.6.5 of this Attachment AE.

4.1.2.6 External Dynamic Resource

Each Market Participant may submit Resource Offers for External Dynamic Resources ("EDR") using the same Offer parameters available to any other Resource, except that:

(1) A Market Participant may only submit a commitment status as defined in Section 4.1(10)(a) or (d) of this Attachment AE;

(2) For an EDR in the Eastern Interconnection, a Market Participant must submit a dispatch status indicating that the EDR is not available for energy dispatch as described under Section 4.1(11)(a) of this Attachment AE;

(3) For an EDR in the Eastern Interconnection, Resource Offer parameters are limited to: Regulation-Up and Regulation-Down Offers, Spinning and Supplemental Reserve Offers, Regulation Ramp Rate, Contingency Reserve Ramp Rate and Resource Status. All other Resource Offer parameters as listed in Section 4.1(9) of this Attachment AE shall not apply to EDRs in the Eastern Interconnection.

(4) For an EDR that is not in the Eastern Interconnection, Resource Offer parameters are limited to: Energy Offer Curve, Ramp-Rate-Up, Ramp-Rate-Down, Regulation-Up and Regulation-Down Offers, Spinning and

Supplemental Reserve Offers, Regulation Ramp Rate, Contingency Reserve Ramp Rate and Resource Status. All other Resource Offer parameters as listed in Section 4.1(9) of this Attachment AE shall not apply to EDRs that are not in the Eastern Interconnection.

4.3.1 Demand Bids

(1) Only Market Participants with registered physical load assets may submit Demand Bids for use in the Day-Ahead Market.

(2) A Market Participant can submit Demand Bids only at Settlement Locations where its physical load assets are registered.

(3) A Market Participant is not permitted to submit a Demand Bid for a load asset pseudo-tied out of the SPP Balancing Authority.

(*4*) A fixed Demand Bid is a specified MW that will be cleared in the Day-Ahead Market regardless of the price at the load Settlement Location based on the start and stop time submitted for the applicable Operating Day.

(*5*) A price sensitive Demand Bid is specified as a Demand Bid Curve. A price sensitive Demand Bid will clear when~~only if~~ the price at the applicable load Settlement Location is less than or equal to the specified Demand Bid Curve price for that Operating Hour.~~ within the specified start and stop time submitted for the applicable Operating Day with ~~The maximum MW amount that can be cleared is equal to the highest Megawatt quantity submitted in the Demand Bid Curve ~~representing the maximum Megawatt amount that can be cleared~~. The minimum MW amount that can be cleared is equal to zero.

6.4.1 Uninstructed Resource Deviation

The following rules apply to the calculation of Uninstructed Resource Deviation ("URD").

(1) *For the purposes of determining URD exemptions for Resources that are part of a Common Bus as described under Section 6.4.1.1(6) of this Attachment AE, each Asset Owner's* Resources' combined average ramped MW Setpoint Instruction and combined actual average MW output at the Common Bus will be used *to calculate* URD *at the Common Bus* for the Dispatch Interval *for each Asset Owner*.

(2) A Resource's URD is allocated a portion of the RUC make whole payment costs, as described under Section 8.6.7 of this Attachment AE, in any Dispatch Interval where Resource's URD is outside of its Operating Tolerance unless that Resource has been exempted from URD.

(a) A generating unit Resource's Operating Tolerance in each Dispatch Interval is equal to the Resource's Maximum Emergency Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(b) A Dispatchable Demand Response Resource's Operating Tolerance in each Dispatch Interval is equal to the resource's Maximum Emergency Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(c) A Block Demand Response Resource's Operating Tolerance in each Dispatch Interval is equal to the resource's Maximum Economic Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(d) The Common Bus Operating Tolerance for each Market Participant registered at a Common Bus is equal to the sum of that Market Participant's Resources' Maximum Emergency Capacity Operating Limits for Resources that are on-line multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(e) If the absolute value of a Resource's URD is greater than the Resource's Operating Tolerance in any Dispatch Interval, the Resource URD / 12 is included in the hourly allocation of RUC make whole payment cost allocation. The Hourly URD amount is calculated as the sum of Dispatch Interval URD for the hour. Additionally, if that Resource was eligible to receive a RUC make whole payment, the payment may be reduced in accordance with Section 8.6.5 of this Attachment AE.

6.4.1.1 Uninstructed Resource Deviation Exemptions

A Resource~~'s~~ will receive a URD exemption in a Dispatch Interval ~~will be considered equal to zero (0)~~ under the following situations:

(1) The Resource is deployed for Contingency Reserve *as described in Section 6.3.2 of this Attachment AE or is deployed for a Contingency Reserve test as described under Sections 2.10.1 and 2.10.2 of this Attachment AE*; or

(2) The Resource trips off-line or is derated after receiving Dispatch Instructions; or

(3) There is missing or bad Resource SCADA data in the Dispatch Interval; or

(4) If during Emergency Conditions the URD is *due to a Resource output* above the Resource's Setpoint Instruction in a shortage condition or the URD is *due to a Resource output* below the Resource's Setpoint Instruction during an excess generation condition; or

(5) If a Dispatch Instruction is issued to a Resource beyond the reported capabilities due to the application of a VRL; or

(6) If the Resource is part of a Common Bus and the URD calculated at the Common Bus is less than the Operating Tolerance calculated at the Common Bus; or

(7) If the URD results from an event of force majeure or, in the case of a Variable Energy Resource, if the URD results from extremely high wind or other extreme weather-related conditions materially and directly impacting a Variable Energy Resource's ability to provide or reduce output of Energy. For purposes of this subsection, ~~-~~the term force majeure shall have the meaning described under Section 10.1 of this Tariff except that acts of Curtailment shall not qualify for exemption. ~~The Market Participant must provide the Transmission Provider with~~

~~adequate documentation through the invoice dispute process in order for the Market Participant to be eligible to avoid such URD. The Transmission Provider will determine through the dispute process whether such URD should be waived~~; or

(8) If the Resource has been issued a Manual Dispatch Instruction.

In the event a Resource does not receive a URD exemption in a Dispatch Interval, the Transmission Provider shall determine through the dispute process, in accordance with the invoice dispute process as provided in Section 10.3 of this Attachment AE, whether an exemption to an Uninstructed Resource Deviation will be given. The Market Participant may provide the Transmission Provider with adequate documentation in order for the Market Participant to be eligible to avoid such Uninstructed Resource Deviation. Adequate documentation may include but is not limited to an audio file documenting a call between the Market Participant and the Transmission Provider.

6.4.1.2 Load Deviation Exemptions

A load is exempt from deviation based charges for cost allocation under Section 8.6.7 under the following situations:

(1) The RTBM billable metering for load is less than that load's Day-Ahead Market cleared quantity during a capacity shortage condition Emergency.

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. 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. Eligible Entities may create Resource specific Transmission Service reservations that represent their current Transmission Service reservations using the process described in the Market Protocols.

(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.

8.3 Calculation of Locational Marginal Prices, Locational Marginal Price Components, and Market Clearing Prices

An LMP shall be calculated for each Meter Settlement Location for the Day-Ahead Market and RTBM and shall be calculated as the price at that location based on the SCED and Operating Reserve clearing, the Dispatchable Resource Energy Offer Curve, Operating Reserve Offer prices and Resource characteristics submitted by Market Participants and data from the State Estimator. The following rules will be used in calculating the LMPs:

(1) LMPs are calculated by the Transmission Provider for each hour in the Day-Ahead Market and each Dispatch Interval in the RTBM as part of the SCED solution described under Section 6.2.2 of this Attachment AE. In performing these calculations, Dispatchable Resources will be eligible to set the LMP under the following conditions:

(a) The Dispatchable Resource must be operating below its maximum capacity limit;

(b) The Dispatchable Resource must be operating above its minimum capacity limit; and

(c) The Dispatchable Resource output must not be ramp rate constrained such that the Dispatchable Resource cannot achieve the optimal desired dispatch point under the economic dispatch.

(2) The Transmission Provider shall calculate LMPs, MCCs and MLCs for use in settlement as follows:

(a) An LMP, MCC and MLC shall be calculated for each Meter Settlement Location for each hour in the Day-Ahead Market and for every Dispatch Interval in the RTBM.

(b) The LMP, MCC and MLC for a load Settlement Location or a Demand Response Load location with multiple Meter Settlement Locations for an hour within the Day-Ahead Market or a Dispatch Interval within the RTBM shall be equal to the load weighted average of LMPs calculated for Meter Settlement Locations aggregated to that Settlement Location or Demand Response Load location for that hour or Dispatch Interval. The load weights utilized in this calculation for the Day-Ahead Market shall be based upon a historical Real-Time load calculated at each Meter Settlement Location by the State Estimator and for the RTBM shall be based upon the actual Real-Time load calculated at each Meter Settlement Location by the State Estimator in that Dispatch Interval.

(c) The LMP, MCC and MLC for a Resource Settlement Location for an hour in the Day-Ahead Market and for a Dispatch Interval in the RTBM shall equal the LMP, MCC and MLC calculated for that Settlement Location for the Resource or, in the case of a Block Demand Response Resource, the LMP, MCC and MLC calculated at the associated Demand Response Load location.

(d) The LMP, MCC and MLC for a Market Hub Settlement Location for an hour within the Day-Ahead Market or a Dispatch Interval within the RTBM shall be equal to the weighted average of LMPs, MCCs and MLCs calculated for Price Nodes within the Market Hub aggregated to that Market Hub Settlement Location for that hour or Dispatch Interval. The weights utilized in this calculation for the Day-Ahead Market shall be determined by the Transmission Provider, in consultation with Market Participants, at the time the Market Hub is created.

(e) The LMP, MCC and MLC for an External Interface Settlement Location for an hour within the Day-Ahead Market or a Dispatch Interval within the RTBM shall be equal to the weighted average of LMPs, MCCs and MLCs calculated for Price Nodes within the External Interface aggregated to that External Interface Settlement Location for that hour or Dispatch Interval. The weights utilized in this calculation for the Day-Ahead Market and RTBM shall be determined by the Transmission Provider at the time the External Interface is created.

(3) If there is insufficient capacity to meet the Energy requirements on a system-wide basis, Energy requirements are reduced to meet available capacity and LMPs are calculated as described under Section 8.3.1.

(4) In the event a failure of the Day-Ahead Market systems results in the loss of the ability to clear the Day-Ahead Market in a timely manner, the TCR charge type described under Section 8.5.11 shall continue to be settled as part of the Day-Ahead Market settlement using the MCCs calculated for the corresponding Operating Day for the RTBM and the congestion revenue collected as part of the RTBM settlement. TCR uplift calculated under Section 8.5.12 shall be set equal to zero and the differences between amounts paid under Section 8.5.11 and available real-time congestion revenue shall be accounted for under Section 8.8. In the event a failure of the Day-Ahead Market systems results in the loss of the ability to clear the Day-Ahead Market, the Transmission Provider will set the Day-Ahead Market LMP, MLC, and MCP to zero.

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

(a) If the failure of the RTBM systems occurs for twelve (12) Dispatch Intervals or less, the estimated LMPs and LMP components shall be the most recently calculated LMPs, MCCs, and MLCs for each affected Settlement Location and shall be utilized for settlement purposes for each of the Dispatch Intervals in which LMP pricing data is missing.

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

(6) If for any reason a portion of generation and load within the SPP Balancing Authority Area becomes isolated from the rest of the SPP Balancing Authority Area ("Island"), the Transmission Provider shall calculate LMPs, MCCs, and MLCs for the RTBM within the Island using mitigated Offers for Resources within the Island in a manner that reflects, as closely as practicable, the LMPs, MCCs, and MLCs within the Island that would have resulted as if the RTBM systems had calculated the values, and shall use such LMPs, MCCs, and MLCs for settlement purposes within the Island for each of the Dispatch Intervals.

10.2 Invoices

(1) The Transmission Provider shall issue an invoice detailing all charges and payments specified in Section 8 of this Attachment AE on a weekly basis in accordance with the invoice issue dates specified in the Market Protocols.

(2) The Transmission Provider shall make payments to the Market Participant for any net credit shown on the invoice and the Market Participant shall make payment to the Transmission Provider for any net charge shown or the invoice, including disputed amounts. Resolution of disputed amounts shall be shown as an adjustment on future invoices.

(3) Market Participants shall make payment to the Transmission Provider that is equal to the net charge shown on the invoice by no later than 5:00 PM on the ~~3rd~~4th business day following the day the invoice was issued.

(4) The Transmission Provider shall make payment to the Market Participant that is equal to the net credit shown on the invoice by no later than 5:00 PM on the ~~5~~6th business day following the day the invoice was issued subject to the procedures specified under Section V of Attachment L.

(5) All payments to the Market Participant and all payments to the Transmission Provider shall be made by electronic funds transfer in U.S. dollars.