Markets+ Draft Tariff

MPEC Approved Language

Revision 2

***<u>Disclaimer</u>: This language has been approved by the Markets+ Participant Executive Committee (MPEC). However, it is subject to modifications pending future stakeholder discussion. ***

CURRENT REVISION

Revision	Date	Description of Edits
V1	8/25/2023	Added language approved by MPEC 8/8/2023: • Attachment A: ○ Section 1 – 3.5.2; 6.7-3.7.1 **Note: Language and sections bracketed will require additional discussion and will potentially be modified at a future time.*

V2	12/8/2023	Added language approved by MPEC 10/19/2023, 11/6-7/2023, and 12/6-7/2023
		• Section I
		• Attachment A:
		  ○ Sections 2.1.1-2.1.3; 2.3.2; 4-4.2.8; 4.3; 5-5.1.2; 5.3-5.4; 6-7.15; 8-8.3; 9.2.1-9.2.12; 9.3.1; 9.3.16-9.3.17; 9.8, 9.9; 11-11.5;
		  ○ Appendix 1
		  ○ Appendix 2
		  ○ Addendum 1
		• Attachment D Transmission Supporting M+
		• Attachment E – MP Agreement
		• Attachment F – Non-Disclosure Agreement
		• Attachment G – MA Agreement
		• Attachment H – Credit Policy
		• Attachment I – Distribution of Other Revenues
		• Attachment J – Allocation of Costs Associated with Penalties

SECTION I – COMMON SERVICE PROVISIONS

1 Definitions

A - Definitions

Aggregator of Retail Customers (ARC)

A Market Participant that registers demand response on behalf of one or more eligible retail customers, for which the participant is not such customers' LSE, and intends to offer that demand response directly into Markets+.

Ancillary Service Plan

A plan submitted by a Market Participant with regulation service and contingency reserve service obligations to meet its next day obligations and current day obligations.

Asset Owner

An aggregation of assets defined by a Market Participant through the Market Operator's registration process that is eligible to be represented by the Market Participant through any combination of Resource and load.

Authorized Agency

A state public utility commission that regulates, within the Markets+ Footprint, the distribution or supply of electricity to retail customers or is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers; (ii) the Markets+ State Committee or any successor organization formed to act as a regional state committee within Markets+; or (iii) a state agency that has both access to documents in the possession of a state public utilities commission pursuant to state statute and the ability to protect those documents in accordance with Attachment F of this Tariff.

Authorized Requestor

An individual who has executed the Non-Disclosure Agreement found in Attachment F of this Tariff and is authorized by an Authorized Agency to receive and discuss Confidential Information.

B - Definitions

Balancing Authority (BA)

A responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time in order to:

(1) Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) Maintain scheduled interchange with other Balancing Authorities, within the limits of Good Utility Practice;

(3) Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) Provide for sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Balancing Authority Area

The collection of generation, transmission, and loads within the metered boundaries of a Balancing Authority. A Balancing Authority maintains load-resource balance within this area.

Behind-the-Meter Generation

A generation unit that is connected on the load side of a load Meter Settlement Location and is used by the load Market Participant that is the registered owner of that Meter Settlement Location to serve all or part of its capacity, energy, or ancillary service needs.

Bid

A commitment to pay a specific maximum price for a quantity of Energy that includes a Demand Bid, a Virtual Energy Bid, or an Export Interchange Transaction Bid.

Billable Metered Load

The Reported Load adjusted as described under Section 9.3.1.1 of Attachment A.

Business Day

A day on which the Federal Reserve System is open for business.

C – Definitions

Calendar Day

Any day including Saturday and Sunday.

Combined Interest Resource

A Resource registered to reflect shared interest of multiple Asset Owners and modeled as one commercial Resource. Credits and charges for these Resources are allocated post market using the submitted interest share percentages.

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 Markets+.

Commit Time

The time specified by the Market Operator in a Market Commitment at which a Resource is to be synchronized and operating at or above its Minimum Economic Capacity Operating Limit. For an MSR, this is the time specified by the Market Operator in a Market Commitment at which the Resource should be connected and at or above its Minimum Discharge Limit or its Minimum Charge Limit.

Common Bus

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

Composite Energy Offer

A Market Operator-calculated Energy Offer for a Fast-Start Resource arrived at by modifying each price point on the Energy Offer Curve for each market interval of the Minimum Run Time by adding amortized start-up and no-load costs.

Conditional Firm Point-To-Point Transmission Service

The reservation and transmission of capacity and energy on a conditional firm basis from specified Point(s) of Receipt to specified Point(s) of Delivery. This service is equivalent to Firm Point-To-Point Transmission Service except that, under certain system conditions or under a number of hours in real-time, this service will be curtailed ahead of Firm Point-To-Point Transmission Service, as further defined in each transmission service provider's Open Access Transmission Tariff (OATT).

Confidential Information

Information containing or revealing:

(1) Any proprietary or commercially or competitively sensitive information, trade secret or information regarding a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Market Participant, which is designated as confidential by that Market Participant when supplying the information to the Market Operator, whether conveyed orally, electronically, in writing, through inspection, or otherwise; or

(2) Any software, products of software or other vendor information that SPP is required to keep confidential under its agreements.

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

Congestion Rent

Revenue collected by the Market Operator resulting from binding transmission constraints in the Day-Ahead Market that will be allocated to Congestion Rent Eligible Transmission Service Reservation (CRETSR) Holders and Markets+ Transmission Service Providers.

Congestion Rent Eligible Transmission Service Reservation (CRETSR)

The MW quantity of Firm Point-to-Point Transmission Service, Conditional Firm Point-To-Point Transmission Service, Network Integration Transmission Service, and/or Legacy Transmission Service of a monthly or longer service increment that spans the full applicable calendar month, that has not been opted out, and is available for use by Markets+.

Congestion Rent Eligible Transmission Service Reservation (CRETSR) Holder

A Market Participant with a Congestion Rent Eligible Transmission Service Reservation.

Control Status

A parameter communicated electronically to the Market Operator by a Market Participant at any time during an Operating Hour indicating a Resource's ability to follow Dispatch Targets.

Coordinated Interchange Scheduling Limit

A constraint activated in Markets+ that establishes the maximum allowable net scheduled interchange between two Balancing Authority Areas (BAAs) at a specified location within the Markets+ footprint.

D - Definitions

Data Error

A data error shall be the following:

(i) Data received by the Market Operator from an independent source, including data produced by a system or submitted by a third party, that is inaccurately modified by the Market Operator during the execution of a market function; or

(ii) Data received by the Market Operator from an independent source, including data produced by a system or submitted by a third party, that is patently incorrect and is used by the Market Operator during the execution of a market function; or

(iii) Incorrect data produced and used by Market Operator during the execution of a market function.

Day-Ahead

The time period starting at 0001 and ending at 2400 on the day prior to the Operating Day.

Day-Ahead Market

The market for Energy and Flexibility Reserve Products that is conducted on the day prior to the Operating Day.

Day-Ahead Market Commitment Period

The contiguous period of time between a Resource's Day-Ahead Market Commit Time and Day-Ahead Market Shutdown Time.

Demand Bid

A proposal by a Market Participant associated with a physical load to purchase a fixed or price sensitive amount of Energy at a specified location and period of time in the Day-Ahead Market.

Demand Bid Curve

A Demand Bid specified as megawatt and dollars per megawatt hour with up to ten (10) price/quantity pairs.

Demand Curve

A series of quantity/price points used to set Locational Marginal Prices and Market Clearing Prices when there is a shortage of Energy or Flexibility Reserve Products.

Demand Response Load

A registered measurable load that is capable of being reduced at the instruction of the Market Operator and subsequently may be increased at the instruction of the Market Operator.

Demand Response Resource (DRR)

A controllable load available for dispatch by the Market Operator that can reduce the withdrawal of Energy from the transmission grid, and for which an Offer Curve has been submitted.

Desired Dispatch

A MW value calculated from a Resource's RTBM Energy Offer Curve between the minimum operating limit and the maximum operating limit that first exceeds the DLMP at the Resource. A Dispatchable Variable Energy Resource's Desired Dispatch will be no greater than the Resource's Real-Time Capability, if available, or the lesser of the maximum operating limit and the Transmission Provider output forecasted for that Resource.

Designated Network Resource (DNR)

Any designated generating resource owned, purchased, or leased by a Network Customer for the purposes of serving Network Load, as further defined in each Markets+ Transmission Service Provider's Open Access Transmission Tariff (OATT).

Dispatch Interval

The interval for which the Market Operator issues Market Commitments for Markets+ in the RTBM. The Dispatch Interval is five (5) minutes.

Dispatch Locational Marginal Price (DLMP)

The price for Energy at a given Price Node that results from the co-optimization of Energy and Flexibility Reserve Products, based on the Bids, Energy Offers, and Flexibility Reserve Product Offers submitted by the Market Participants. The DLMP does not include Fast-Start Resource composite Energy Offers, as described in Section 3.1.

Dispatch Target

The communicated Resource target Energy megawatt output level at the end of the Dispatch Interval.

Dispatchable Resource

A Resource for which an Offer Curve has been submitted and that is available for dispatch by Market Operator.

Dispatchable Variable Energy Resource (DVER)

A Variable Energy Resource registered in Markets+ that is capable of being dispatched by the Market Operator.

E – Definitions

Electric Storage Resource (ESR)

A resource capable of receiving electric energy and storing it for later injection of electric energy to the grid. A resource that is either (1) physically incapable of injecting electric energy to the Transmission System due to its design or configuration or (2) contractually barred from injecting electric energy to the Transmission System is excluded from this definition.

Electric Storage Resource Loss Factor

The factor that represents round-trip efficiency related to the amount of Energy an ESR loses from charge to discharge. This loss factor is the ratio of (1) the Energy the ESR is able to inject via discharge to (2) the Energy withdrawn in order to store that charge.

Electrical Node (Enode)

A physical node represented in the Network Model where electrical equipment and components are connected.

Emergency Condition

A condition or situation determined by a Reliability Coordinator, Balancing Authority, or Transmission Operator within the Markets+ Footprint that is imminently likely to cause damage to or a materially adverse effect on the reliability or security of the Bulk Electric System.

Emergency Condition Commitment

A Balancing Authority, Reliability Coordinator or Transmission Operator commitment issued to address an Emergency Condition within the Markets+ Footprint. These commitments are initiated during an Operating Day and are based on projected local reliability requirements, operational considerations, and generation and transmission outages that were not anticipated prior to the Operating Day.

Energy

An amount of electricity that is Bid or Offered, produced, purchased, consumed, sold, or transmitted over a period of time, which is measured or calculated in megawatt hours.

Energy Offer Curve

A set of monotonically non-decreasing price/quantity pairs that consists of megawatts and dollars per megawatt hour with up to ten (10) price/quantity pairs.

Energy Schedule

A set of hourly energy injection and withdrawal values, in megawatts per hour, submitted by Market Participants.

Export Interchange Transaction

A Market Participant schedule for exporting Energy out of the Markets+ Footprint.

Export Interchange Transaction Bids

A proposal by a Market Participant to purchase a fixed or price sensitive amount of Energy for delivery outside of the Markets+ Footprint at a specified External Interface and for a period of time.

External Interface

A Settlement Location representing a physical interconnection point(s) between a Balancing Authority Area within the Markets+ Footprint and a Balancing Authority Area external to the Markets+ Footprint.

External Resource

A Resource located outside of the Markets+ Footprint that is included in a Markets+ Balancing Authority Area through an External Resource Pseudo-Tie.

External Resource Pseudo-Tie

A non-physical electrical interconnection point between Balancing Authorities, whereby all or a portion of an External Resource in one Balancing Authority Area is considered to be in another Balancing Authority Area within the Markets+ Footprint.

F – Definitions

Fast-Start Resource (FSR)

A Resource with the following submitted offer parameters for a Day-Ahead Market or Real-Time Balancing Market interval: (1) a Start-Up Time offer of ten (10) minutes or less; and (2) a Minimum Run Time offer of sixty (60) minutes or less. MSRs must also have a Minimum Discharge Time offer of sixty (60) minutes or less to qualify as a Fast-Start Resource. MCRs must also have a Group Minimum Run Time offer of sixty (60) minutes or less to qualify as a Fast-Start Resource.

Federal Energy Regulatory Commission (FERC)

An independent, federal agency that regulates the interstate transmission and wholesale sale of natural gas, oil, and electricity.

Firm Point-To-Point Transmission Service

The reservation and transmission of capacity and energy on a firm basis from specified Point(s) of Receipt to specified Point(s) of Delivery, as further defined in each transmission service provider's Open Access Transmission Tariff (OATT).

Flexibility Reserve Product Offer

The price at which a Resource has agreed to sell offline Flexibility Reserve Products. Flexibility Reserve Product Offers do not apply to online Flexibility Reserve Products.

Flexibility Reserve Products

Flexibility Reserve Products include Short-Term Flex Up, Short-Term Flex Down, and Mid-Term Flex Up.

G – Definitions

Good Utility Practices

Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, safety, and expedition. Good Utility Practices is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts, generally accepted by the region.

Group Minimum Down Time

For an MCR, the minimum length of time a defined group of configurations must remain offline following transition to a different defined group of configurations.

Group Minimum Run Time

For an MCR, the minimum length of time a defined group of configurations must run from the time the group is put online to the time the group is shut down.

H – Definitions

High-Priority Export Interchange Transaction

An Export Interchange Transaction that is backed by committed export supply. Committed export supply includes Market Participant Resource Adequacy Program obligations to load outside the Markets+ Footprint. Committed export supply also includes source specific sales to load outside the Markets+ Footprint where the portion of the export that is High Priority is the portion that is supported by an identified Resource's available surplus capacity. High Priority Export Interchange Transactions will be included in the Market Participant's Must Offer Obligation.

High-Priority Import Interchange Transaction

An Import Interchange Transaction that is backed by committed import supply. High Priority Import Interchange Transactions may be used to meet a Market Participant's Must Offer Obligation.

Hybrid Storage Market Resource (HSMR)

Generating resource(s) and ESR(s) located behind the same point of interconnection that are registered together in Markets+ as a single Resource.

I – Definitions

Import Interchange Transaction

A schedule for importing Energy into the Markets+ Footprint.

Import Interchange Transaction Offer

A proposal by a Market Participant to provide Energy from a source external to a Markets+ Balancing Authority Area at a specified External Interface and period of time.

Instantaneous Load Capacity

The achievable change in real power output required to account for differences between the average load and the projected instantaneous load.

Information Request

A written request for disclosure of Confidential Information pursuant to Section 10.4 of Attachment A to the Tariff.

Interchange Transaction

Any Energy transaction that is crossing the boundary of the Markets+ Footprint and requires checkout with one or more Balancing Authority Areas external to the Markets+ Footprint. This includes any Import Interchange Transaction, Export Interchange Transaction, or Through Interchange Transaction.

J - Definitions

Jointly Owned Unit

A Resource that is:

1) Owned by more than one Market Participant; or
2) A Resource for which (a) one or more entities, at least one of which is a Market Participant, have contractual rights or financial obligations and (b) which the Market Participant registers as a Jointly Owned Unit.

K - Definitions

L – Definitions

Legacy Transmission Service

Transmission service that existed on a transmission service provider's system prior to the effective date of that transmission service provider's Open Access Transmission Tariff (OATT) that is equivalent to Network Integration Transmission Service (NITS) or Firm Point-To-Point Transmission Service.

Load Responsible Entity (LRE)

A Market Participant with registered load in Markets+.

Load Serving Entity (LSE)

A distribution utility or an electric utility that has a service obligation, where a service obligation, as defined in Section 217(a) of the Federal Power Act, means a requirement applicable to, or the exercise of authority granted to, an electric utility under federal, state, or local law, or under long-term contracts to provide electric service to end-users or to a distribution utility.

Local Reliability Issue

A local voltage or reliability issue necessitating a Local Reliability Issue Commitment issued by a Balancing Authority or Reliability Coordinator.

Local Reliability Issue Commitment

A Balancing Authority, Reliability Coordinator, or Transmission Operator commitment issued to address a Local Reliability Issue within the Markets+ Footprint. These commitments are initiated prior to or during an Operating Day and are based on projected local reliability requirements, operational considerations, and generation and transmission outages.

Local Settlement Area

A geographic area equivalent to a Balancing Authority participant area.

Locational Marginal Price

The marginal price of Energy at a given Price Node as calculated by the Market Operator's Simultaneous Co-optimization Methodology.

M – Definitions

Marginal Congestion Component

The calculated portion of the Locational Marginal Price at a Settlement Location representing transmission congestion costs between that Settlement Location and a reference location as calculated under Section 3.2.2 of this Attachment A.

Marginal Energy Component

The compound Locational Marginal Price at a Reference Bus.

Marginal Loss Component

The calculated portion of the Locational Marginal Price at a Settlement Location representing marginal loss costs between that Settlement Location and a reference location as calculated under Section 3.2.1 of this Attachment A.

Market Clearing Price

The price used for settlement of a Flexibility Reserve Product in each Reserve Zone.

Market Commitment

The Day-Ahead Market or Reliability Unit Commitment processes results communicated by the Market Operator to a Market Participant to (i) either start up or shut down a specified Resource and/or (ii) transition an MCR from one configuration to another.

Market Monitor

The Market Monitor established under the Tariff.

Market Operator

The entity that operates Markets+ in accordance with this Tariff.

Market Participant

An entity that generates, transmits, distributes, purchases, or sells electricity in Markets+. Market Participant expressly including any entity offering Resources for sale into Markets+ that executes the Service Agreement specified in Attachment E to this Tariff, or on whose behalf an unexecuted Service Agreement has been filed at FERC.

Markets+ Footprint

The geographic region defined by the Balancing Authorities participating in Markets+ under this Tariff.

Markets+ Internal Energy Schedule

Market Participants will have the ability to schedule a physical transfer of energy from a specific resource (or group of resources) to a specific load inside the Markets+ footprint, as demonstrated by an e-Tag and supported by a commitment of such resources to load, including through ownership or forward contractual obligation. To the extent the identified resource(s) receive a market dispatch, the output of such resources shall be considered delivered to the specified load.

Markets+ Internal Energy Schedule Settlement Adjustment

An accounting mechanism that reflects the physical transfer of energy based on an energy schedule with the source and the sink inside the Markets+ Footprint.

Markets+ Tariff

The Tariff describing Markets+ including all schedules or attachments thereto, as amended from time to time and approved by FERC.

Markets+ Transmission Contributor

Any Market Participant that voluntarily provides its transmission service rights on a non-participating transmission service provider's system for Markets+ optimization.

Markets+ Transmission Service

Any transmission capability that has been identified by Transmission Service Providers and Transmission Service Contributors to the Market Operator as available to Markets+, regardless of whether the capacity has been reserved or scheduled.

Markets+ Transmission Service Contributor

Any Transmission Service Customer under a Markets+ Market Participant's Open Access Transmission Tariff within the Markets+ Footprint that voluntary provides its transmission service capacity to the market for optimization in order to provide Markets+ Transmission Service.

Markets+ Transmission Service Provider

Any transmission service provider in the Markets+ Footprint that executes the agreement for a Markets+ Transmission Service Provider in Markets+ and contributes Markets+ Transmission Capability.

Markets+ Transmission User

Any Market Participant offering or bidding load, generation, interchange, or virtual transactions within Markets+.

Maximum Economic Capacity Operating Limit

An economic MW level used for constraining Energy dispatch that includes reductions to account for the Operating Reserve identified in the Ancillary Service Plan.

Maximum Charge Limit

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

Maximum Charge Time

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

Maximum Discharge Limit

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

Maximum Discharge Time

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

Maximum Emergency Charge Limit

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

Maximum Emergency Discharge Limit

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

Maximum State of Charge

The maximum State of Charge that should not be exceeded.

Meter Agent

An entity responsible for collecting load and Resource data associated with identified Meter Settlement Locations within a Settlement Area for the purpose of energy accounting that impacts market settlements. Meter Agent may refer to a Market Participant performing the Meter Agent function on its own behalf, or to a Meter Agent designated by the Market Participant to act on its behalf in accordance with the Tariff.

Meter Data

Real power measurement of Resources, loads, or tie-line flows between Settlement Areas and external Balancing Authority Areas, including pseudo-ties, and any other electrical quantities required for market settlement.

Meter Data Submittal Location

One or more Meter Settlement Locations contained within a single Settlement Area for which Meter Data is submitted to the Market Operator by the Meter Agent for settlement purposes.

Meter Settlement Location

The effective point at which a Market Participant's registered load and Resources interchange Energy within the Markets+ Footprint.

Mid-Term Flex Up

A Flexibility Reserve Product, procured by the Market Operator from the portion of a dispatchable and participating Resource's capability that is reserved for potentially increasing net obligations for future Dispatch Intervals.

Minimum Charge Limit

The minimum MWs level an MSR is able to withdraw from the grid during normal operating conditions.

Minimum Charge Time

The minimum duration of time an MSR is able to withdraw from the grid.

Minimum Discharge Limit

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

Minimum Discharge Time

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

Minimum Economic Capacity Operating Limit

A megawatt level at or above a Resource's Minimum Capacity Operating Limit used for Energy dispatch at a minimum level during normal operating conditions.

Minimum Emergency Charge Limit

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

Minimum Emergency Discharge Limit

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

Minimum Run Time

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

Minimum State of Charge

The minimum State of Charge that should be maintained.

Min-to-Off Time

The time for a Resource to de-synchronize from the grid starting from the Resource's Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Minimum Charge Limit, as applicable.

Multi-Configuration Resource (MCR)

A combined cycle Resource registered consistent with the offer submission option as defined under Section 4.2.9 of this Attachment A.

Multi-Day Reliability Advisory Process

A non-binding, informational study that provides a commitment and pricing forecast based on the latest available forecast and commitment data.

N – Definitions

Net Benefits Test

A calculation that measures the threshold price at which the benefits of dispatching Demand Response Load outweigh the costs.

Network Customer

An entity receiving Network Integration Transmission Service under one or more Markets+ Transmission Service Provider's Open Access Transmission Tariff (OATT).

Network Integration Transmission Service (NITS)

The reservation and transmission of capacity and energy on a firm basis between Designated Network Resources and Network Load, as further defined in each Markets+ Transmission Service Provider's Open Access Transmission Tariff (OATT).

Network Model

A representation of the transmission, generation, and load elements of the interconnected transmission systems within the Markets+ Footprint.

No-Load Offer

The compensation request in a Resource Offer, in dollars, by a Market Participant representing the hourly fee for operating a synchronized Resource at zero (0) megawatt output. For a generating unit, No-Load Offers are generally representative of the fuel expense required to maintain synchronous speed at zero (0) megawatt output. For a Dispatchable Demand Response Resources, No-Load Offers are generally representative of a combination of the fuel expense required to maintain synchronous speed at zero (0) megawatt output for Behind-The-Meter Generation and the ongoing hourly costs associated with manufacturing process changes associated with a reduction in load consumption. For an MSR, No-Load Offers are the cost to

maintain a State of Charge when the MSR has a zero (0) MW output (i.e., the Resource is operating under a "No-Load" condition).

Non-Conforming Load

Load that is process driven that does not follow a predictable pattern.

Non-Dispatchable Variable Energy Resources (NDVER)

A Variable Energy Resource registered in the Markets+ Footprint that is not capable of being incrementally dispatched by the Market Operator.

O – Definitions

Offer

A commitment to sell a quantity of Energy at a specific minimum price that includes a Resource Offer, a Virtual Energy Offer or an Import Interchange Transaction Offer.

Operating Day

A daily period beginning at midnight Pacific Prevailing Time (PPT).

Operating Hour

A sixty (60) minute period of time beginning at the top of the hour, typically expressed as hour-ending.

Operating Tolerance

The megawatt range of actual Resource output above and below the Resource's average Dispatch Instruction over the Dispatch Interval where the Resource will not be subject to charges associated with Uninstructed Resource Deviation.

Out-of-Merit Energy (OOME)

An instruction from a Reliability Coordinator, Balancing Authority, or a Markets+ Transmission Operator, to address an Emergency Condition or Local Reliability Issue.

P - Definitions

Pacific Prevailing Time (PPT)

As established by national time standards, either Pacific Standard Time or Pacific Daylight Time.

Plant Minimum Down Time

For an MCR, the minimum length of time required following complete desynchronization that the entire combined cycle plant must remain offline prior to a subsequent synchronization.

Plant Minimum Run Time

For an MCR, the minimum length of time the combined cycle plant must run from the time the plant is committed to the time the plant is shut down.

Portal

Internet interface between the Market Operator and its Markets+ participants.

Price Node (Pnode)

A node in the Commercial Model where Locational Marginal Prices are calculated.

Q - Definitions

R – Definitions

Ramp-Rate-Down

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

Ramp-Rate-Up

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

Resource Adequacy Program

The Western Resource Adequacy Program.

Real-Time Balancing Market (RTBM)

The market operated by the Market Operator continuously in real-time to balance the system through deployment of Energy and to clear Flexibility Reserve Products.

Real-Time Capability

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

Real-Time Load Ratio Share

The sum of a Market Participant's Billable Meter, Self-Charging MSRs, and Export Interchange Transactions at all Settlement Locations within the Balancing Authority Area divided

by the sum of all Market Participants' Billable Metered Load, Self-Charging MSRs, and Export Interchange Transactions at all Settlement Locations with the Balancing Authority Area for a given hour.

Reference Bus

The location on the Transmission System within the Markets+ Footprint relative to which all mathematical quantities will be calculated.

Reliability Coordinator

The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

Reliability Unit Commitment (RUC)

The processes performed by the Market Operator to assess resource and Flexibility Reserve Product adequacy and to communicate Market Commitments of Resources to the appropriate Market Participants as necessary.

Reliability Unit Commitment Period

The contiguous period of time between a Resource's Reliability Unit Commitment Commit Time and Reliability Unit Commitment Shutdown Time.

Reported Load

The actual megawatt-hour quantity withdrawn from the transmission grid at a Meter Data Submittal Location, as submitted by the Meter Agent. For Meter Data Submittal Locations not submitted by the Meter Agent, State Estimator values for those locations are used.

Reserve Zone

A zone containing a specific group of Price Nodes for which minimum and maximum Flexibility Reserve Product requirements are calculated.

Resettlement

The settlement of an Operating Day subsequent to the posting of the S120 Scheduled Settlement Statement for that Operating Day.

Residual Load

TThe sum of (a) injections at each Meter Data Submittal Location within the Settlement Area and (b) withdrawals at each Meter Data Submittal Location within the Settlement Area and (c) the sum of all Energy into and out of a Settlement Area.

Resource

Assets registered in Markets+ that inject Energy into the transmission grid, or reduce the withdrawal of Energy from the transmission grid, and may be self-dispatched or directly dispatched by the Market Operator.

Resource Offer

A Resource's Start-Up Offer, No-Load Offer, Energy Offer Curve, Transition State Offer, physical operating parameters, and Flexibility Reserve Product Offer.

S – Definitions

S7 Scheduled Settlement Statement

As defined in Section 9.9(1) of Attachment A to this Tariff.

S53 Scheduled Settlement Statement

As defined in Section 9.9(2) of Attachment A to this Tariff.

S120 Scheduled Settlement Statement

As defined in Section 9.9(3) of Attachment A to this Tariff.

Scarcity Price

The Locational Marginal Price and Market Clearing Price levels determined through the use of Demand Curves when there are insufficient Energy or Flexibility Reserve Products.

Scarcity Pricing

The calculation of Scarcity Prices in accordance with Sections 3.2 and 3.6.1 of this Attachment A.

Scheduled Settlement

The mandatory settlement of an Operating Day that is posted on a prescribed schedule.

Scheduled Settlement Statement

The statement produced from a Scheduled Settlement.

Self-Charging

Withdrawing Energy from the Transmission System without a Market Operator Dispatch Target.

Service Flow Constraint

An operating constraint limit that respects each Markets+ Transmission Service Contributors, Markets+ Transmission Service Providers, and participating Balancing Authorities' transmission capability communicated to the Market Operator. Service Flow Constraints will be continuously activated in the Simultaneous Co-optimization Methodology to constrain the least cost dispatch to the transmission capability made available for use in Markets+.

Setpoint Target

The real-time target megawatt output signal calculated for a specific Resource by the Market Operator for a specified period within a Dispatch Interval.

Settlement Area

An area within a single Balancing Authority for which interval metering can account for the net injections and net interchange associated with that area.

Settlement Invoice

A weekly summary of Markets+ net daily charges and payments by Asset Owner and Operating Day that is generated for each Market Participant and contains data for all of the Operating Days settled, either on a Scheduled Settlement or Resettlement basis, during the invoice period. For each Operating Day, only the net amounts (current total less previously invoiced) contribute to the invoice amounts.

Settlement Location

A location comprised of one or more Meter Data Submittal Locations for calculation of settlements in the Day-Ahead Market and Real-Time Balancing Market. The five (5) types of Settlement Locations are: Resource (including pseudo-tied resources), Load (including pseudo-tied loads), Trading Hub, Resource Hub, and External Interface.

Settlement Statement

A daily summary of the Markets+ total daily charges and payments by charge type, Market Participant, Asset Owner and Operating Day which is generated for each Market Participant and contains data for all of the Operating Days settled, either on a Scheduled Settlement or Resettlement basis. For each Operating Day, the current, previous and net amounts are included on the statement.

Shadow Price

A price for a commodity that measures the marginal value of the commodity.

Short-Term Flex Down

A Flexibility Reserve Product, procured by the Market Operator from a Resource capable of following Dispatch Targets, that is reserved to provide downward flexibility during periods in which net obligations decrease in future Dispatch Intervals.

Short-Term Flex Up

A Flexibility Reserve Product, procured by the Market Operator from a Resource capable of following Dispatch Targets, that is reserved to provide upward flexibility during periods in which net obligations increase in future Dispatch Intervals.

Shutdown Time

The time specified by the Market Operator or a local transmission operator in a Market Commitment at which a Resource is to begin de-synchronization procedures.

Simultaneous Co-optimization Methodology

An algorithm capable of committing, clearing, dispatching, and pricing Energy and Flexibility Reserve Products on a co-optimized basis that minimizes overall costs while enforcing multiple security constraints.

Software Error

Software results inconsistent with the requirements of Attachment A to this Tariff**.**

Start-Up Offer

The compensation required by a Market Participant to bring an off line Resource on line or to reduce consumption of a Dispatchable Demand Response Resource.

Start-Up Time

The time required to start a Resource and reach the Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Minimum Charge Limit, as applicable, following receipt of a Market Commitment.

State Estimator

A standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable.

State of Charge

The amount of Energy stored expressed in megawatt-hours.

State of Charge Forecast

The projected State of Charge for the beginning of each market interval used in the Day-Ahead Market and the RUC.

Synchronized Resource

A Resource that is electrically connected to the grid as evidenced by the closing of the Resource circuit breaker.

Sync-to-Min Time

The time required for a Resource's output to reach Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Minimum Charge Limit, as applicable, following synchronization to the grid.

T – Definitions

Third Party Request

Any request or demand by any entity upon an Authorized Requestor or an Authorized Agency for release or disclosure of Confidential Information. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, request pursuant to state freedom of information or public records access statutes or regulations, or other request for Confidential Information made by any: (i) federal, state or local government subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual. This provision is subject to any applicable exception under Section 10 of Attachment A to the Tariff.

Through Interchange Transaction

A Market Participant schedule submitted between two External Interfaces for use in the Day-Ahead Market or Real-Time Balancing Market for moving Energy through the Markets+ Footprint.

Trading Hub

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

Transition State Offer

An offer representing the cost to move an MCR to another configuration.

Transition State Time

An operating parameter representing the time required to move an MCR to another configuration.

Transmission Operator

The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.

U – Definitions

Uncommitted Export Interchange Transaction

An Export Interchange Transaction that is not a High-Priority Export Interchange Transaction.

Uncommitted Import Interchange Transaction

An Import Interchange Transaction that is not a High-Priority Import Interchange Transaction.

Uninstructed Resource Deviation (URD)

The megawatt amount by which a Resource's actual output in a Dispatch Interval is above or below that Resource's average Setpoint Target over a Dispatch Interval.

V – Definitions

Variable Energy Resource

A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Violation Relaxation Limit (VRL)

The values described under Section 7.9 of Attachment A to this Tariff.

Virtual Energy Bid

A proposal by a Market Participant to purchase Energy at a specified price, Settlement Location and period of time in the Day-Ahead Market that is not associated with a physical load.

Virtual Energy Offer

A proposal by a Market Participant to sell Energy at a specified price, Settlement Location and period of time in the Day-Ahead Market that is not associated with a physical Resource.

Virtual Transactions

Virtual Transactions include Virtual Energy Offers and Virtual Energy Bids.

W - Definitions

XYZ – Definitions

2 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of SPP, acting by and through authorization from the SPP Board of Directors, to make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

3 Force Majeure and Indemnification

3.1 Force Majeure

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, cyberattack, riot, pandemic, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation, or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing by the party claiming Force Majeure. Neither Market Operator nor the Market Participant will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff. A Market Participant that has experienced a Force Majeure event must notify the Market Operator as soon as practicable and identify the Force Majeure event and the obligations affected by the event. If the Market Operator has experienced a Force Majeure event, it must notify all Market Participants as soon as practicable and identify the Force Majeure event and the obligations affected by the event. Notwithstanding the foregoing, the physical inability to perform because of an event of Force Majeure shall not relieve the party of any financial obligations incurred under this Tariff or as a result of the Force Majeure event, unless such financial obligation is waived or excused under this Tariff.

3.2 Liability

(a) SPP shall not be liable, whether based on contract, indemnification, warranty, tort, strict liability or otherwise, to any Market Participant, third party, or other person, for any damages whatsoever, including, without limitation, direct, incidental, consequential, punitive, special, exemplary, or indirect damages for any actions or omissions by SPP in performing its obligations as Market Operator under this Tariff or any agreement hereunder, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of service, except to the extent such act or omission by SPP is found to result from its gross negligence or intentional wrongdoing, in which case SPP will only be liable for direct damages.

(b) A Markets+ Transmission Service Provider shall not be liable for damages to any Markets+ Transmission User for actions or omissions by such Markets+ Transmission Service Provider or SPP in performing its obligations under this Tariff or any agreement hereunder, except to the extent such act or omission by such Markets+ Transmission Service Provider is found to result from its gross negligence or intentional wrongdoing.

(c) A Markets+ Transmission User, third party, or other person may not seek to enforce any claims under this Tariff or any agreements entered into under this Tariff against the directors, members, managers, shareholders, officers, employees or agents of SPP or a Markets+ Transmission Service Provider, and such individuals will have no personal liability for obligations of SPP or a Markets+ Transmission Service Provider solely by reason of their status as directors, members, managers, shareholders, officers, employees or agents of SPP.

(d) In the event that SPP is required to pay any money damages, compensation, or attorney's fees and costs to a Market Participant, third party, or other person, for any actions or omissions by SPP in performing its obligations as Market Operator under this Tariff or any agreement hereunder, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of service, SPP shall be allowed to recover any such amounts pursuant to the procedures in this Tariff.

(e) In no event shall a Markets+ Transmission Service Provider be liable to any Markets+ Transmission User for any incidental, consequential, punitive, special, exemplary or indirect damages, attorney's fees and costs, loss of revenues or profits, arising out of, or connected in any way with the performance or non-performance under this Tariff or any Service Agreement thereunder.

3.3 Indemnification

The Market Participants shall at all times indemnify, defend, and save SPP, and any of its agents, consultants, directors, officers, or employees, harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person, or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations

by or to third parties, arising out of or resulting from SPP's performance of obligations under this Tariff as Market Operator, except in cases of gross negligence or intentional wrongdoing by SPP or its agents, consultants, directors, officers, or employees.

3.4 Limitation on Claims

Except as may be required to comply with applicable Federal Energy Regulatory Commission orders, no claim seeking an adjustment in the billing for any service, transaction, or charge under the Tariff may be asserted if more than one (1) year has elapsed since the Operating Day at issue. SPP shall make no adjustment to billing with respect to any service, transaction, or charge under this Tariff if more than one (1) year has elapsed since the Operating Day at issue.

4 Creditworthiness

The SPP Creditworthiness procedures are specified in Attachment H.

5 Dispute Resolution Procedures

5.1 Internal Dispute Resolution Procedures

Any dispute between a Market Participant(s) and the Market Operator involving service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Market Participant Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Market Operator and a senior representative of the Market Participant for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days (or such other period as the parties may agree upon) , such dispute may be submitted to arbitration by mutual agreement and resolved in accordance with the arbitration procedures set forth below.

5.2 External Arbitration Procedures

Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the parties. If the parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each party shall choose one arbitrator who shall sit on a three-member arbitration panel, except that if more than two parties are involved, the parties shall agree on procedures to choose these two arbitrators. If the parties are unable to agree, then the American Arbitration Association shall be asked to appoint the arbitrator(s). The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or regional transmission group rules.

5.3 Arbitration Decisions

Unless otherwise agreed, the arbitration shall be conducted in accordance with the Commercial Arbitration Rules of the American Arbitration Association. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Market Participant Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the parties, and judgment on the award may be entered in any court having jurisdiction; provided, however, that final decisions with the federal government (including Power Marketing Agencies) as one of the parties are nonbinding. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms, and conditions of service or facilities.

5.4 Costs

Each party shall be responsible for its own costs, including its attorney's fees and costs, incurred during the arbitration process and for the following costs, if applicable:

(i) the cost of the arbitrator chosen by the party or parties to sit on the three-member panel and its equal share of the cost of the third arbitrator chosen; or

(ii) its equal share of the cost of the single arbitrator jointly chosen by the parties.

5.5 Rights Under the Federal Power Act

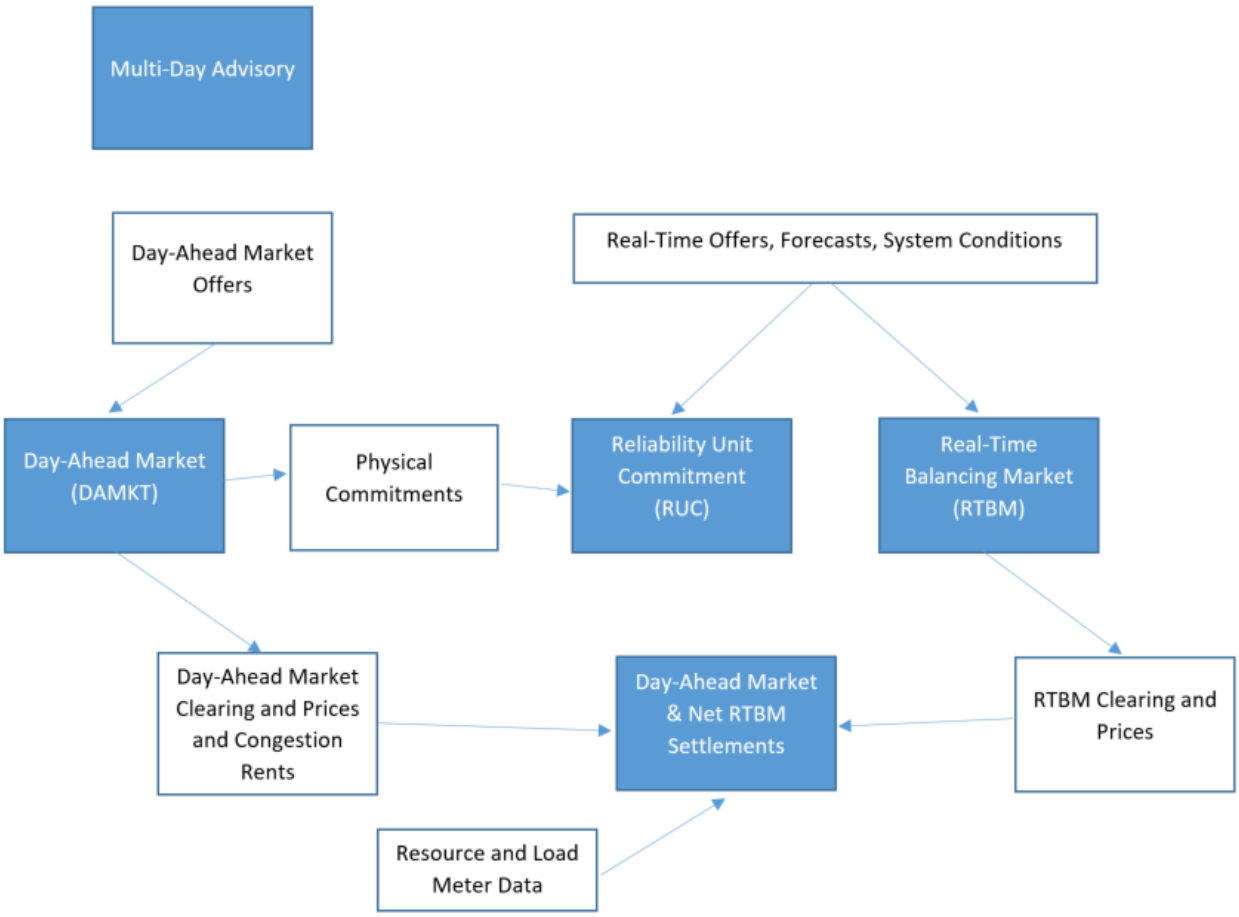
Nothing in this Tariff shall restrict the rights of any party under the Federal Power Act.

ATTACHMENT A
Markets Plus

Table of Contents

1. Introduction

This Attachment sets forth the Bidding, Offering, and dispatching responsibilities of the Market Operator and Market Participants relating to Markets+, and sets forth the operation, pricing, and settlement of the Day-Ahead Market and the Real-Time Balancing Market ("RTBM"). All time references in this Attachment A shall be the prevailing time as specified in the Markets+ Protocols. Figure 1 shows the relationships and general timing sequence between the various market processes.



2. Day-Ahead and Operating Day Activities

2.1 Day-Ahead Activities

The Market Operator shall conduct the Day-Ahead Market as described in the subsections below. Offers and Bids must be submitted by the close of the Day-Ahead Market which is 10:00 PPT Day-Ahead. The Market Operator shall post the Day-Ahead Market results from the dispatch solution no later than 13:30 PPT Day-Ahead. The Market Operator may extend these times as necessary, and shall notify Market Participants of any such timing delays. The Market Operator will post the Day-Ahead Market LMP and MCP results from the pricing solution after the posting of the dispatch solution results.

2.1.1 Day-Ahead Market Inputs

Inputs to the Day-Ahead Market will include the following:

(1) Day-Ahead Market Resource Offers, Demand Bids, Virtual Energy Offers, and Virtual Energy Bids;

(2) Through Interchange Transactions;

(3) Export Interchange Transaction Bids;

(4) Import Interchange Transaction Offers;

(5) Balancing Authority Operating Reserve Requirements;

(6) Flexibility Reserve Products requirements (system-wide and Reserve Zone minimum and maximum);

(7) Transmission System topology consistent with the Network Model in place for the upcoming Operating Day;

(8) Scheduled Outages (Resource and Transmission);

(9) Service Flow Constraints;

(10) [GHG info needed];

(11) Instantaneous Load Capacity requirements; and

(12) Local Reliability Issue Commitments.

2.1.2 Day-Ahead Market Execution

The Market Operator will employ a Simultaneous Co-optimization Methodology to perform the following tasks to clear the Day-Ahead Market for each hour of the upcoming Operating Day, while recognizing Transmission System security constraints, Service Flow Constraints, and the Resource operating parameter constraints submitted as part of the Day-Ahead Market Offers:

(1) Commit Offered Resources, Import Interchange Transaction Offers and Virtual Energy Offers to meet the Demand Bids, Virtual Energy Bids, Export Interchange Transactions Bids, Instantaneous Load Capacity requirements, and Flexibility Reserve Products requirements on a least-cost basis.

(2) Using the Resource commitment results, clear Resource Offers, Virtual Energy Offers and Import Interchange Transaction Offers to meet Demand Bids, Virtual Energy Bids, Export Interchange Transaction Bids and Flexibility Reserve Products requirements on a least-cost basis.

2.1.2.1 Clearing During Capacity Shortage

(1) In the event of a Flexibility Reserve Product(s) shortage in any hour, the Market Operator will implement Scarcity Pricing.

(2) In the event a capacity shortage results in an inability to meet fifty percent (at least 50%) of the Mid-Term Flex Up requirement, the Self-Scheduled Demand Bids, Self-Scheduled High Priority Export Interchange Transactions, Self-Schedule Uncommitted Export Interchange Transactions, and Resources' charge MWs in any hour, the Market Operator will:

(a) First reduce the Self-Scheduled Uncommitted Export Interchange Transactions on a pro-rata basis based on the MW amounts until such time that the Mid-Term Flex-Up requirement is restored and administratively set LMPs as described under Section 3.6.4(4);

(b) If the reduction of all Uncommitted Export Interchanges Transaction does not restore the Mid-Term Flex-Up requirement, reduce Self-Scheduled Demand Bids,

Self-Scheduled High Priority Export Interchange Transactions, and Resources' charge MWs on a pro-rata basis based on the MW amounts to match the available capacity.

(3) If a transmission constraint cannot be relieved due to a shortage of capacity in any hour, the Self-Schedule Demands Bids will clear on a pro-rata basis based upon the impact on relieving the constraint.

2.1.2.2 Clearing During Excess Generation Conditions

If the sum of Self-Scheduled Demand Bids, Self-Scheduled Uncommitted Export Interchange Transaction Bids, and Self-Scheduled High Priority Export Interchange Transaction Bids in any hour are less than the sum of the minimum outputs of the committed Resources, Self-Scheduled Uncommitted Import Interchange Transaction Bids, and Self-Scheduled High Priority Import Interchanges Transaction Bids in that hour, then the Market Operator will:

(a) Reduce Self-Schedule Uncommitted Import Interchanges Transaction Bids pro-rata based on MW amounts;

(b) Reduce Self-Schedule High Priority Import Interchange Transactions Bids pro-rata based on MW amounts;

(c) Relax enforcement of Resource minimum limits on a pro-rata basis to clear Resource Offers to meet Demand Bids, Uncommitted Export Interchange Transaction Bids, High Priority Export Interchange Transaction; and

(d) Implement Scarcity Pricing to the extent that the Flexibility Reserve Products requirements cannot be maintained.

2.1.3 Day-Ahead Market Results

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

A. The following results are communicated to each Market Participant for only its specific Resources, no later than the posting of the Day-Ahead Market:
   (1) Cleared Resource quantities for Energy and Flexibility Reserve Products;
      (a) Cleared Offers for Energy associated with Resource Offers represent a Market Commitment.
      (b) Resources committed by the Market Operator in the Day-Ahead Market that incur one or more start-up costs within the Operating Day as a result of the Market Commitment are guaranteed to receive revenues that are at least equal to the Resource Offer costs for the cleared amount of Energy and Flexibility Reserve Products.
   (2) [Cleared Virtual Energy Offers];
   (3) Cleared Import Interchange Transaction Offers;
   (4) Cleared Demand Bids;
   (5) [Cleared Virtual Energy Bids];
   (6) Cleared Export Interchange Transaction Bids; and
   (7) Cleared Through Interchange Transactions.

B. The following dispatch solution results are communicated to all Market Participants prior to the posting of the pricing solution results:
   (1) Dispatchable Locational Marginal Prices (DLMPs) for each Settlement Location, the marginal Energy component ("MEC") of the DLMP, the Marginal Congestion Component ("MCC") of the DLMP and the Marginal Loss Component ("MLC") of the DLMP for each Settlement Location; and
   (2) MCPs for Flexibility Reserve Products.

C. The following pricing solution results are communicated to all Market Participants after the posting of the dispatch solution results:
   (1) LMPs for each Settlement Location, the marginal Energy component ("MEC") of the LMP, the Marginal Congestion Component ("MCC") of the LMP and the Marginal Loss Component ("MLC") of the LMP for each Settlement Location; and

(2) MCPs for Flexibility Reserve Products.

2.2 Reliability Unit Commitment

The Market Operator will begin the RUC processes no earlier than 45 minutes following the posting of the Day-Ahead Market results to assess capacity adequacy during the Day-Ahead period and the remainder of the current Operating Day.

2.2.1 Reliability Unit Commitment Inputs

Inputs to the RUC will include the following:

(1) RTBM Resource Offers;

(2) Approved Export Interchange Transaction;

(3) Approved Import Interchange Transaction;

(4) Approved Through Interchange Transactions;

(5) Flexibility Reserve Products requirements (system-wide and Reserve Zone minimum and maximum);

(6) Market Operator load forecast;

(7) Transmission System topology consistent with Network Model in place for the upcoming RUC study period;

(8) Service Flow Constraints;

(9) Resource commitment schedules;

(10) The Market Operator's wind and solar Resource MWh output forecast;

(11) Actual and approved scheduled Transmission System outages as documented in the Transmission Provider's outage scheduler;

(12) Instantaneous Load Capacity requirements;

(13) Balancing Authority overrides;

(14) [Local Reliability Issue Commitments; and

(15) Emergency Condition Commitments.]

2.2.2 Reliability Unit Commitment Execution

The Market Operator will employ a Simultaneous Co-optimization Methodology with the objective of committing Resources to meet the Market Operator load forecast, Uncommitted Export Interchange Transactions, High Priority Export Interchange Transactions, Instantaneous Load Capacity requirements, and Flexibility Reserve Products requirements less Uncommitted Import Interchange Transactions and High Priority Import Interchange Transactions over the study period such that commitment costs are minimized while recognizing Transmission System security constraints, Service Flow Constraints, and the Resource operating parameter constraints submitted as part of the RTBM Offers.

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

(2) If available capacity plus Uncommitted Import Interchange Transactions plus High Priority Import Interchange Transactions is not sufficient on a system-wide basis to meet the Market Operator load forecast, Uncommitted Export Interchange Transactions, High Priority Export Interchange Transactions, the upper bound of Instantaneous Load Capacity requirement and fifty percent (50%) of the Mid-Term Flex Up requirement, the Market Operator will communicate and coordinate with Market Participants and participating BAs to sequentially:

   (a) Reduce Uncommitted Export Interchange Transactions pro-rata based on MW amounts to relieve the capacity shortage; and

   (b) Commit additional available Resources that were not otherwise offered to the market to relieve the capacity shortage if needed. Each Market Participant will be required to identify and make available such additional supply, as defined in the Markets+ Protocols, subject to the Market Participant's contractual rights and obligations and any operational limitations as determined by the Market Participant and/or participating BA.

(3) If there is a capacity surplus on a system-wide basis identified when the sum of (a) self-committed and reliability must-run capacity at minimum output, (b) Self-Schedule Uncommitted Import Interchange Transactions, (c) High Priority Import Interchange

Transactions (d) the lower bound of Instantaneous Load Capacity requirement, and (e) the Flexibility Reserve Products requirements is more than the sum of the Market Operator load forecast, Self-Scheduled Uncommitted Export Interchange Transactions and Self-Scheduled High Priority Export Interchange Transactions the Market Operator will:

(a) Reduce Self-Schedule Uncommitted Import Interchanges Transaction Bids pro-rata based on MW amounts;

(b) Reduce Self-Schedule High Priority Import Interchange Transactions Bids pro-rata based on MW amounts; and

(c) Communicate and coordinate with participating BAs.

2.2.3 Reliability Unit Commitment Results

The Market Operator shall communicate the following results to Market Participants:

(1) Modification of existing Market Commitments; and

(2) New Market Commitments.

2.3 Operating Day Activities

2.3.1 Real-Time Balancing Market

The Market Operator will employ the Simultaneous Co-optimization Methodology to clear the RTBM while meeting Flexibility Reserve Products requirements within the Markets+ Footprint.

2.3.1.1 Real-Time Balancing Market Inputs

Inputs into the RTBM will include the data provided prior to each Operating Hour and data provided within each Operating Hour, including the following:

(1) RTBM Resource Offers;

(2) Approved Through Interchange Transactions;

(3) Approved Export Interchange Transaction Bids;

(4) Approved Import Interchange Transaction Offers;

(5) Balancing Authority Operating Reserve Requirements;

(6) Flexibility Reserve Products requirements (system-wide and Reserve Zone minimum and maximum);

(7) Scheduled Transmission System outages;

(8) Instantaneous Load Capacity requirements;

(9) Latest State Estimator solution;

(10) Real-Time Resource telemetry;

(11) Active transmission constraints;

(12) Service Flow Constraints;

(13) Market Operator load forecast;

(14) The Market Operator's wind and solar Resource output forecast; and

(15) [Resource commitments including Resource commitments and Resource de-commitments, from the Day-Ahead Market and RUC processes, Resource commitments and Resource decommitments associated with Local Reliability Issue Commitments and Resource commitments and Resource decommitments associated with Emergency Condition Commitments].

2.3.1.2 Real-Time Balancing Market Execution

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

(1) A Simultaneous Co-optimization Methodology is employed to calculate Resource Dispatch Targets and clear Flexibility Reserve Products to meet the Market Operator load forecast and Flexibility Reserve Products requirements at minimum costs based upon submitted Offers while recognizing Resource operating constraints, transmission constraints, and Service Flow Constraints.

(2) In certain situations, enforcing constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, the Market Operator will apply VRLs within the Simultaneous Co-optimization Methodology

(3) During shortage situations:

(a) If there is an actual shortage of Short-Term Flex Up and/or Mid-Term Flex Up during a Dispatch Interval, either on a system-wide or a Reserve Zone basis, Scarcity Prices will be implemented on a system-wide basis or Reserve Zone basis to set Short-Term Flex Up and/or Mid-Term Flex Up MCPs as described under Section 3.6 of this Attachment A.

(b) In the event a capacity shortage results in an inability to meet 50% of the Mid-Term Flex Up requirement, the Short-Term Load Forecast, Self-Scheduled High Priority Export Interchange Transactions, Self-Schedule Low Priority Export Interchange Transactions and Resources' charge MWs in any hour, Market Operator will:

(i) First reduce the Self-Scheduled Low Priority Export Interchange Transactions on a pro-rata basis based on the MW amounts in accordance with WECC schedule change requirements until the Mid-Term Flex-Up requirement is restored and administratively set LMPs as described under Section 3.6.4(4) of this Attachment A; and

(ii) Maintain power balance through the implementation of VRLs to reduce the Short-Term Load Forecast, Self-Scheduled High Priority Export Interchange

Transactions, and Resources' charge MWs on a pro-rata basis based on the MW amounts to match the available capacity; and

(iii) Communicate the market capacity shortage condition to Markets+ Balancing Authority Areas and Markets+ Reliability Coordinators.

(4) During excess situations:

If the sum of Short-Term Load Forecast, Self-Scheduled Uncommitted Export Interchange Transaction Bids, and Self-Scheduled High Priority Export Interchange Transaction Bids in any hour are less than the sum of the minimum outputs of the committed Resources, Self-Scheduled Uncommitted Import Interchange Transaction Bids and Self-Scheduled High Priority Import Interchanges Transaction Bids in that hour, then the Market Operator will:

(a) Reduce Self-Schedule Uncommitted Import Interchanges Transaction Bids pro-rata based on MW amounts in accordance with WECC schedule change requirements;

(b) Reduce Self-Schedule High Priority Import Interchange Transactions Bids pro-rata based on MW amounts in accordance with WECC schedule change requirements;

(c) Communicate the excess market generation situation to Markets+ Balancing Authority Areas and Markets+ Reliability Coordinators; and

(d) Implement Scarcity Pricing to the extent that the Flexibility Reserve Products requirements cannot be maintained.

2.3.1.3 Real-Time Balancing Market Results

(1) Following execution of the Simultaneous Co-optimization Methodology, the Market Operator shall communicate the results to Market Participants for only their specific Resources prior to the start of the applicable Dispatch Interval:

(a) Resource Dispatch Targets; and

(b) Cleared Flexibility Reserve Products.

(2) The following pricing solution results are communicated to all Market Participants after the posting of the dispatch solution and are used for settlement purposes;

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

(b) MCPs for Flexibility Reserve Products for each Reserve Zone.

2.3.1.4 Out-of-Merit Energy Dispatch

[Need details on who will be communicating the OOME to the Market]

When the Market Operator receives notification of an OOME, the Market Operator will incorporate and reflect the OOME in the RTBM at either the fixed MW level or an OOME cap and/or OOME floor MW level the Resource is expected to produce.

2.3.1.4.1 Determination of Non-Discriminatory Manual Resource Selection

Any process used by BAs, reliability coordinators, and Transmission Operators to manually select Resources for out-of-merit energy dispatch must not be unduly discriminatory. The Market Monitor will consider cost, any affiliation with selected Resources, resource operating parameters, availability of non-selected Resources relative to the selected Resources and any prior instances where the Resources were committed to resolve the same reliability issue. The commitment will be considered non-discriminatory if the Resource selection was made without regard to ownership and the selected Resource effectively and economically mitigated the reliability issue, as verified by the Market Monitor. The Market Monitor will make best efforts to perform such verification before the S120 Scheduled Settlement Statements are issued, for the Operating Day in which the manual commitment occurred. In order to include the costs in the make-whole payments by the S120 Settlement Statement, the submission must occur within seventy-five (75) calendar days after the Operating Day and the verification must be complete no later than noon on the business day prior to 105 calendar days after the Operating Day. [If the Market Monitor cannot obtain the documentation it needs to verify non-discriminatory resource selection, then the Market Monitor may make a referral to FERC.]

2.3.2 Congestion Management

(1) The Market Operator will incorporate the data provided by Reliability Coordinators, Markets+ Transmission Service Providers and participating Balancing Authorities for congestion management in the dispatch solution. This data includes:

(a) Out-of-Merit Energy;

(b) Applicable transmission constraints; and

(c) Changes to Interchange Transactions.

(2) The Market Operator will constrain the least-cost dispatch to the transmission capability made available for use in Markets+ through the continuous activation of Service Flow Constraints.

3. Locational Marginal Prices and Market Clearing Prices

3.1 Day-Ahead Market and RTBM Dispatch and Pricing

The Simultaneous Co-optimization Methodology used in the Day-Ahead Market and RTBM produces both a dispatch solution and a pricing solution. The dispatch solution and pricing solution are executed independent of each other. The MW quantities used in settlements for the dispatch and clearing of Energy and Flexibility Reserve Products result from the dispatch solution. Except where specified as DLMP, prices used in settlements result from the pricing solution and will be specified as LMP, MCC, MCP, MEC, and MLC. The DLMP results from the dispatch solution. The differences between the dispatch solution and the pricing solution are:

(1) Simultaneous Co-optimization Methodology dispatch solution

(a) DLMP developed from the Co-optimization of Energy and Flexibility Reserve Products is based on the Energy Offers and Bids and Flexibility Reserve Products Offers submitted by the Market Participants.

(2) Simultaneous Co-optimization Methodology pricing solution

(a) For non-FSRs, co-optimization of Energy and Flexibility Reserve Products is based on the Energy Offers and Bids and Flexibility Reserve Products Offers submitted by the Market Participants.

(b) For FSRs, excluding self-committed FSRs, the Market Operator calculates a composite Energy Offer for use in the co-optimization of Energy and Flexibility Reserve Products. The composite Energy Offer will be calculated and applied as follows:

(i) The Market Operator calculates a composite Energy Offer for an FSR by modifying each price point on the Energy Offer Curve for each market interval of the Minimum Run Time by adding amortized start-up and no-load costs. For FSRs that are MSRs, the composite Energy Offer applies only to the discharge portion of the Energy Offer curve.

1. The commitment costs (i.e., start-up cost and no-load cost) in effect at the time of the commitment are amortized over the Maximum Economic Capacity Operating Limit and the Minimum Run Time.

a. The start-up cost added to each breakpoint of the Energy Offer Curve is calculated by dividing the Start-Up Offer by the Maximum Economic Capacity Operating Limit and by the Minimum Run Time rounded up to the nearest interval.

b. The no-load cost added to each breakpoint of the Energy Offer Curve is calculated by dividing the No-Load Offer by the Maximum Economic Capacity Operating Limit and by the ratio of the number of intervals needed to meet the Minimum Run Time to the number of intervals in an hour.

2. The application of the composite begins with the commitment interval and extends through the Minimum Run Time.

(c) Except in case of self-committed FSRs, FSRs will have their minimum operating limit relaxed to 0 MW.

For Day-Ahead Market and RTBM Simultaneous Co-optimization Methodology, mitigation measures for Energy Offers and Flexibility Reserve Products Offers, described under Sections 3.2 and 3.4 of Attachment B of this Tariff, will be performed in the Simultaneous Co-optimization Methodology pricing solution.

An FSR's composite Energy Offer curve will be subject to the Safety-net Energy Offer Cap.

3.2 Locational Marginal Prices and Locational Marginal Price Components

LMPs are calculated by the Market Operator for each hour in the Day-Ahead Market and each Dispatch Interval in the RTBM.

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 dispatch point under the economic dispatch.

The LMP at a PNode is the cost of delivering an incremental MW of energy at that specific PNode, while satisfying all operational constraints where such cost will include applicable Demand Curve prices if the incremental MW of energy would result in a corresponding increase in shortage conditions. The LMP at any PNode is the sum of three components: the marginal costs of Energy (the MEC), the marginal cost of losses (the MLC), and the marginal cost of congestion (the MCC).

LMP Components at $PNode_i$ are calculated based upon the following formula:

$LMP_i = MEC + MLC_i + MCC_i$

Where:

(1) MEC is the component of LMP_i representing the marginal cost of Energy;

(2) MLC_i is the component of LMP_i representing the marginal cost of losses at $PNode_i$ relative to the Reference Bus;

(3) MCC_i is the component of LMP_i representing the marginal cost of congestion at $ENode_i$ relative to the Reference Bus; and

(4) The Reference Bus represents the network distributed load bus.

3.2.1 Marginal Losses Component Calculation

The MLC_i at each $Pnode_i$ is defined by the following equations:

$MLC_i = -MLSF_i * MEC$

$MLSF_i = \partial (Losses) / \partial P_i$

Where:

(1) Losses = Transmission System losses in the Markets+ Footprint;

(2) $MLSF_i$ = Marginal loss sensitivity factor at $PNode_i$;

(3) MEC is the component of LMP_i representing the marginal cost of Energy;

(4) P_i = Net Injection at $Pnode_i$

The $MLSF_i$ is a linearized estimate of the change in Markets+ Transmission System losses that will result from a 1 MW injection at $PNode_i$ coupled with a corresponding withdrawal at the Reference Bus to maintain global power balance. Marginal loss sensitivity factors are dependent on topology, node injections and node withdrawals.

3.2.2 Marginal Congestion Component Calculation

The MCC at each $PNode_i$ is defined by the following equations:

$MCC_i = - \sum_{k=1}^{K} (Sensi_{ik} * SP_k)$

$Sensi_{ik} = \partial Flow_k / \partial P_i$

Where:

(1) k is the number of transmission constraints;

(2) $Sensi_k$ is the linearized estimate of the change in the constraint k flow resulting from an incremental energy injection at $PNode_i$ coupled with an incremental energy withdrawal at the Reference Bus;

(3) $Flow_k$ = Calculated flow for constraint k;

(4) SP_k = is the Shadow Price of constraint k.

(5) P_i = Net Injection at $Pnode_i$

3.2.3 Marginal Energy Component Calculation

The MEC is defined as the computed LMP at the Reference Bus. By definition, MCC and MLC components are zero (0) at the Reference Bus.

3.3 Application of Locational Marginal Prices

The Market Operator shall derive an LMP for each Settlement Location for the Day-Ahead Market and RTBM by aggregating the LMPs calculated at individual Price Nodes. The following rules will be used in deriving an LMP for Settlement Locations as follows:

(1) Load Settlement Location LMP shall be equal to the load weighted average of LMPs calculated for individual Price Nodes for that hour or Dispatch Interval.

(a) The load weights utilized in this calculation for the Day-Ahead Market shall be based upon a historical real-time load calculated at each Settlement Location by the State Estimator for each hour.

(b) The load weights utilized in this calculation for the RTBM shall be based upon the actual real-time load calculated at each Settlement Location by the State Estimator in that Dispatch Interval.

(2) Demand Response Load location with multiple Settlement Locations shall be equal to the load weighted average of LMPs calculated for Settlement Locations aggregated to that Settlement Location or Demand Response Load location for that hour or Dispatch Interval.

(a) The load weights utilized in this calculation for the Day-Ahead Market shall be based upon a historical real-time load calculated at each Settlement Location by the State Estimator for each hour.

(b) The load weights utilized in this calculation for the RTBM shall be based upon the actual real-time load calculated at each Settlement Location by the State Estimator in that Dispatch Interval.

(3) Resource Settlement Location LMP for an hour in the Day-Ahead Market and for a Dispatch Interval in the RTBM shall equal the LMP calculated for Price Node for the Resource.

(4) The LMP for a Trading Hub Settlement Location for an hour within the Day-Ahead Market or a Dispatch Interval within the RTBM shall be equal to the average of LMPs, MCCs and MLCs calculated for Price Nodes within the Trading Hub aggregated to that Trading Hub Settlement Location for that hour or Dispatch Interval.

(5) The LMP 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 calculated for Price Nodes within the External Interface aggregated to that External Interface Settlement Location for that hour or Dispatch Interval.

(a) The Market Operator shall determine the weights utilized in this calculation for the Day-Ahead Market and RTBM at the time the External Interface is created.

3.4 Market Clearing Price Calculations

The MCP represents the cost of supplying an increment of Flexibility Reserve Product, taking into account lost opportunity cost and is composed of the marginal Flexibility Reserve Product costs and marginal costs associated with Flexibility Reserve Products scarcity. The Day-Ahead Market and RTBM MCPs at a Reserve Zone for Resources with cleared Flexibility Reserve Products in that Reserve Zone are equal to the summation of the applicable Shadow Prices associated with the constraints as described in subsections (1) and (2) below:

(1) There are [two sets] of constraints which apply on both a system-wide basis and a Reserve Zone basis:

(a) A [Flexibility Reserve Product Down] constraint is equal to the [Flexibility Reserve Product Down] requirement; and

(b) A [Flexibility Reserve Product Up] constraint is equal to the [Flexibility Reserve Product Up] requirement.

(2) Flexibility Reserve Products MCPs for each Reserve Zone are calculated as follows:

(a) The [Flexibility Reserve Product Down] MCP is equal to the Shadow Price for the system-wide and zonal [Flexibility Reserve Product Down] constraint; and

(b) The [Flexibility Reserve Products Up] MCP is equal to the Shadow Price for the system-wide and zonal [Flexibility Reserve Products Up] constraint.

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

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

(b) To the extent that the Market Operator is unable to calculate RTBM MCPs, the Market Operator shall use the MCPs generated in the Day-Ahead Market for RTBM settlement.

3.5 Violation Relaxation Limit

The Day-Ahead Market, RUC and Simultaneous Co-optimization Methodology enforce a number of operating constraints in developing the market solution. In certain situations, attempting to enforce all constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, the Market Operator must apply VRLs. The VRL values are listed in Addendum 1 to this Attachment A.

There are four (4) categories of constraints and associated VRLs: (1) Resource capacity constraints; (2) Resource ramp constraints; (3) global power balance constraints and (4) operating constraints (which include Price Node ("Pnode"), Manual, Watch List, flowgate and real-time contingency analysis ("RTCA") constraints). A higher VRL value is an indication of the relative priority for enforcing the constraint type. For example, the VRL value assigned to a ramp rate limit exceeds that assigned to a flowgate limit indicating that the flowgate constraint should be relaxed before the ramp rate constraint. If the VRL with the lowest value will not allow the Simultaneous Co-optimization Methodology to balance the Energy obligations, a higher VRL will be applied. In the case of the operating constraint VRLs, the values limit the cost of the dispatch needed to balance system injections and withdrawals by capping the Shadow Price depending upon the level of the violation.

3.5.1 Impact of Violation Relaxation Limits on Dispatch and Pricing Solutions

VRLs are applied independently in the dispatch solution and pricing solution. The applicable VRLs impact the Simultaneous Co-optimization Methodology in the following manner:

(1) When a VRL is exceeded and cannot be resolved, the applicable constraint is relaxed so that Simultaneous Co-optimization Methodology can solve. The VRL values applied by the Market Operator in this case act as a cap on the Shadow Price on the applicable constraint. LMPs/DLMPs and MCPs are calculated using the relaxed constraints; and

(2) When a VRL is reached but not exceeded, it is referred to as "binding" and has no impact on the Simultaneous Co-optimization Methodology.

3.5.2 Modifications to Violation Relaxation Limits

By [placeholder for future date], the Market Operator shall produce a report with supporting documentation that will analyze the effectiveness of VRLs and associated values on reliability and prices. If changes are warranted, the Market Operator shall recommend changes to the appropriate stakeholder groups for consideration.

By [placeholder for future date], taking into consideration the recommendations of stakeholders and staff, any changes to the VRLs or associated values must be approved for filing by the SPP Board of Directors and then filed with FERC. The most recent FERC-approved VRLs and associated values are in Addendum 1 to this Attachment A.

3.6 Pricing during Scarcity Conditions

If capacity is insufficient 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 3.6.1.

3.6.1 Impact of Scarcity Pricing on Locational Marginal Prices and Market Clearing Prices

(1) Demand Curves are applied independently in the dispatch solution and pricing solution. The Market Operator will use Demand Curves to reflect Scarcity Prices in both the Day-Ahead Market and RTBM during times of Flexibility Reserve Products shortages, either on a system-wide and/or Reserve Zone basis.

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

(a) Short-Term Flex Up – The Market Operator calculates and posts Short-Term Flex Up Scarcity Pricing in accordance with the following rules:

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

(ii) The maximum Scarcity Price will be calculated each month using the previous three months' offer data and will be limited to a maximum of $1,000/MWh. To the extent that three months of offer data is not available, the Market Operator will use the offer data available to calculate the maximum Scarcity Price.

(iii) The Demand Curve levels for Short-Term Flex Up will be equal to:

1. Shortages up to or equal to five percent (5%) of the requirement will equal, to the nearest dollar, 1/6 of the maximum Scarcity Price.

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

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

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

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

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

(iv) The minimum amount for the Short-Term Flex Up Demand Curve prices will be limited to $10.

(b) Short-Term Flex Down – The Market Operator calculates and posts Short-Term Flex Down Scarcity Pricing in accordance with the following rules:

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

Resource's Maximum Economic Capacity Operating Limit or Maximum Discharge Limit as applicable.

(ii) The maximum Scarcity Price will be calculated each month using the previous three months' offer data and will be limited to a maximum of $1,000/MWh. To the extent that three months of offer data is not available, the Market Operator will use the offer data available to calculate the maximum Scarcity Price.

(iii) The Demand Curve levels for Short-Term Flex Down will be equal to:

1. Shortages up to or equal to 5% of the requirement will equal, to the nearest dollar, 1/6 of the maximum Scarcity Price.

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

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

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

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

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

(iv) The minimum amount for the Short-Term Flex Down Demand Curve prices will be limited to $0.

(c) Mid-Term Flex Up – The Market Operator calculates and posts Mid-Term Flex Up Scarcity Pricing in accordance with the following rules:

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

(ii) The maximum Scarcity Price will be calculated each month using the previous three months' offer data and will be limited to a maximum of $1,000/MWh. To the extent that three months of offer data is not available, the Market Operator will use the offer data available to calculate the maximum Scarcity Price.

(iii) The Demand Curve levels for Mid-Term Flex Up will be equal to:

1. Shortages up to or equal to 5% of the requirement will equal, to the nearest dollar, 1/6 of the maximum Scarcity Price.

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

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

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

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

6. Shortages greater than 40% but less than or equal to 50% of the requirement will equal, to the nearest dollar, the maximum Scarcity Price.

7. Shortages greater than 50% of the requirement will equal $1,000/MWh.

(iv) The minimum amount for the Mid-Term Flex Up Demand Curve prices will be limited to $10.

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

(4) During capacity shortage conditions in either the Day-Ahead Market or RTBM:

(a) The MEC component of the LMP will be set to $1,000/MWh to the extent that Low Priority Exports have been reduced until such time that Low Priority Exports have been restored. The MCC and MLC components of LMP will continue to be calculated normally; or

(b) The MEC component of the LMP will be set to $2,000/MWh to the extent that Low Priority Exports have been reduced until such time that Low Priority Exports have been restored, if the MMU has authorized offer prices in excess of $1,000/MWh. The MCC and MLC components of LMP will continue to be calculated normally.

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

(a) If there is a shortage of Short-Term Flex Up, the Short-Term Flex Up MCP will be set equal to the Short-Term Flex Up Demand Curve price. The Short-Term Flex Up Demand Curve price will be reflected in the LMP.

(b) If there is a shortage of Short-Term Flex Down, the Short-Term Flex Down MCP will be set equal to the Short-Term Flex Down Demand Curve price. The Short-Term Flex Down Demand Curve price will be reflected in the LMP.

(c) If there is a shortage of Mid-Term Flex Up, the Mid-Term Flex Up MCP will be set equal to the Mid-Term Flex Up Demand Curve price. The Mid-Term Flex Up Demand Curve price will be reflected in the LMP.

3.7 Special Scenarios Locational Marginal Pricing and Market Clearing Pricing

3.7.1 Locational Marginal Prices and Market Clearing Prices during System Outages

(1) 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 charge type described under Section XYZ 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. [Congestion Rent] calculated under Section XYZ shall be set equal to zero and the differences between amounts paid under Section XYZ and available real-time congestion revenue shall be accounted for under Section XYZ. 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 Market Operator will set the Day-Ahead Market LMP, MLC, and MCP to zero.

(2) In the event a 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 Market Operator 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 Market Operator 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 Market Operator is unable to calculate RTBM LMPs, MCCs, MLCs, and MCPs, the Market

Operator shall use the LMPs, MCCs, MLCs, and MCPs generated in the Day-Ahead Market for RTBM settlement.

3.7.2 Locational Marginal Prices and Market Clearing Prices during Island Conditions and Markets+ Footprint Expansion Cutovers

If a portion of generation and load within the Markets+ footprint [becomes isolated] from the rest of the Markets+ Footprint ("Island"), the Market Operator shall calculate LMPs, MCCs, and MLCs for the Day-Ahead Market and 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 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.

If an RTBM does not approve for the first interval a Markets+ Settlement Location is effective, the Market Operator shall calculate LMPs, MCCs, and MLCs for that Settlement Location using Mitigated Offers for Resources in a manner that reflects, as closely as practicable, the LMPs, MCCs, and MLCs that would have resulted if the RTBM systems had calculated the values, and shall use such LMPs, MCCs, and MLCs for settlement purposes for that Settlement Location until an RTBM approves.

4. Resource Participation

4.1 General Resource Participation

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

(1) Day-Ahead Market Offers are independent from RTBM Offers;

(2) Day-Ahead Market and RTBM Offers will automatically roll forward to the same hour in the following Operating Day within each respective market until an updated Resource Offer has been submitted for that hour;

(3) Day-Ahead Market and RTBM Offers may vary for each hour of the Operating Day, except the Offer parameters related to unit commitment as defined in the Markets+ Protocols for which a single value is submitted;

(4) RTBM Offers are also used in the RUC;

(5) Resource Offers are limited by the Offer caps and floors specified in Section 5.3 of this Attachment A;

(6) The Resource Offer parameters that must be included to constitute a valid Offer for use in either the Day-Ahead Market or RTBM, are defined in the Markets+ Protocols;

(7) Market Participants must specify one of the Resource commitment statuses defined below:

a) **Market –** The Resource is available for Market Operator economic commitment if it is off-line;

b) **Self –** The Market Participant is committing the Resource and the Market Operator should include it as committed in either the DA Market and/or RUC as specified;

c) **Reliability Must Run (RMR) –** Market Participants must only use this commitment status when the Resource received an Emergency Condition Commitment or Local Reliability Issue Commitment and the Market Operator should include it as committed in either the DA Market and/or RUC as specified;

d) **Outage –** The Resource is unavailable to the market, or, in the case of an MCR, the configuration is unavailable to the market;

e) **Not Available –** The Resource did not offer to be available for Markets+ commitment.

(8) Intra-operating hour adjustments to Resource Offer physical operating parameters due to changes in a Resource's capability. Market Participants shall notify the Market Operator of a change in a Resource Offer physical operating parameter during an Operating Hour. For the current Operating

Hour the Market Operator will make the requested modification to the Resource Offer physical operating parameter. For subsequent hours the Market Participant shall remain responsible for accurately reflecting Resource operating parameters in its Resource Offer submissions.

4.2 Additional Resource Participation Types

4.2.1 Demand Response Resources

Market Participants registering a Dispatchable Demand Response Resource must:

(1) Identify an associated Demand Response Load Meter Data Submittal Location; and

(2) Identify an associated Demand Response Load Settlement Location.

In addition to requirements above, Market Participants registering a Dispatchable Demand Response Resource must also specify either the submitted resource production option or calculated resource production option for calculation of the Dispatchable Demand Response Resource output.

The Market Operator will notify the applicable retail provider and the relevant electric retail regulatory authority of the registration and the expected MW level of participation. Additional notification will be provided if modifications are made to the expected megawatt level of participation. If either the relevant electric retail regulatory authority or applicable retail provider disputes the accuracy of the pending registration information or attestations, the Market Operator will notify the Market Participant of the dispute and may pause the Resource's registration, prohibit the Resource in question from participating in Markets+, or not accept the modification until the issue is resolved between the Market Participant and the disputing entity. If resolution has not been reached between the registering Market Participant, relevant electric retail regulatory authority, and, if applicable, the retail provider, within 90 days of the Market Participant's notification of the dispute, the Resource's pending registration or the modification to the existing registration may be cancelled.

(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 of this Attachment A, associated with the Demand Response Load. The Market Participant must submit the real-time value of the Demand Response Load to the Market Operator via telemetering meeting necessary technical requirements. A Dispatchable Demand Response Resource shall submit Energy Offer Curves based on the criteria in Section 3.2 of Attachment B of this Tariff. For purposes of these Resources, the short-run marginal cost may equal opportunity cost. 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 Market Operator 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 Market Operator 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 FERC's regulations; 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 FERC's regulations.

(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 Market Operator 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 Market Operator 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.

(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 in 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 thirty (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 Market Operator 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 Market Operator will perform this assessment each day starting on the thirty-first (31st) day of participation and notify the Market Participant of any adjustment.

(c) If the hourly baseline has not been submitted, the Market Operator shall set the hourly baseline equal to 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.

4.2.2 Electric Storage Resource

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

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

(2) If an ESR is registered as an MSR, the following applies:

a) MSRs may provide Flexibility Reserve Products upon meeting the technical and applicable requirements for these products.

b) MSRs must provide Offer parameters.

c) MSR Offer Curves may include negative MW values to account for the entire dispatchable range of the MSR.

d) As with other Resources, the metering requirements for MSRs include real-time and settlement quality metering.

e) For MSRs that are not directly connected to the Transmission System, metering may include facilities used by the distribution company. In the event that the MSR is not directly connected to the Transmission System and the distribution company is unable or unwilling to separate the charging activity from other retail service, the MSR will not be subject to settlement by the Market Operator for energy consumption.

f) The real-time Energy consumption is settled at the LMP.

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

4.2.3 Hybrid Storage Market Resource

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

(1) HSMRs directly connected to the Markets+ Footprint will have the generating resource(s) be modeled separately behind a single point of interconnection in the Network Model. Physical and operational characteristics, real-time telemetry and other information for the generating resource(s) and the ESR(s) must be provided for individual components to the Market Operator for situational awareness, grid security, and also for informational purposes through telemetry in the Network Model. The submitted revenue Meter Data for settlement of the Resource response will represent the total combined HSMR response at the point of interconnection.

(2) If an HSMR is not registered as an MSR, then the Energy withdrawal from the Markets+ Footprint must be included in a load Settlement Location and is subject to the same rules as other load.

(3) If an HSMR is registered as an MSR then rules in Section 4.2.2(2) of this Attachment A apply.

4.2.4 Variable Energy Resources (VERs)

VERs may register as any valid Resource type and are subject to the following rules:

(1) The Minimum Limits submitted as part of the Day-Ahead Market and/or RTBM Resource Offer must be submitted as zero MW. If these limits are not submitted as zero MW, the Resource Offer will be rejected;

(2) [For Dispatchable Variable Energy Resources (DVERs) with a Maximum Limit of less than 200MW, the maximum ramp rate between MW specified in the Ramp-Rate-Up curve and Ramp-Rate Down curve in the RTBM Resource Offer multiplied by 5 cannot exceed 40MW. For DVERs with a Maximum Limit greater than or equal to 200MW, the maximum ramp rate between MW levels specified in the Ramp-Rate-Up curve and Ramp-Rate-Down curve in the RTBM Resource Offer multiplied by 5 cannot exceed 20% of the DVER's Emergency Maximum Capacity Operating Limit;]

(3) For the RUC process, the maximum operating limit shall be the lesser of the emergency maximum capacity operating limit as specified in the DVER RTBM Offer and SPP's output forecast for that DVER.

(4) DVERs for which SPP is calculating an output forecast are not eligible to receive RUC make whole payments;

(5) For the Real-Time Balancing Market, SPP will provide a dispatch flag to the DVER indicating whether or not the DVER should "follow" or "ignore" its Dispatch Target.

4.2.5 Fuel-Limited Resources

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

4.2.6 Resource Aggregation

Market Participants may register a Resource representing multiple assets of the same fuel type that inject Energy into, or reduce the withdrawal of Energy from, one or more points of the transmission grid within the Markets+ footprint that meet the following:

1. Are electrically similar, and the aggregation does not have a material impact on M+ market operations as determined by the Market Operator; and
2. Are located or pseudo-tied into the same Markets+ Balancing Authority Area; and
3. Share common operational control.

This aggregation is expected to be a long-term selection made by the Market Participant at resource registration and is intended to reflect resources that are operationally linked on a long-term basis. The aggregation may be at the plant or unit level. Physical and operational Resource characteristics, real-time telemetry and other information for each asset in a resource aggregation must be provided to the Market Operator. If, after resource registration, the Market Operator observes that the resource aggregation has or anticipates that the resource aggregation will have a material impact on market operations, then the Market Operator will work with Market Participant to remedy through the resource registration process. The Market Operator recognizes that grouped hydro may not be able to separate hydro aggregations because of river management obligations, recognizing that power production is generally subordinate to other multi-purpose project usage directed by laws including statutes, treaties and operation agreements.

4.2.7 Jointly Owned Units (JOUs)

A Market Participant may register Jointly Owned Units (JOUs) using the individual Resource option or the Combined Interest Resource option.

(1) As part of market registration, the following offer parameters representing the physical characteristics of the entire JOU ("Physical JOU Resource") must be submitted either by or on behalf of the Market Participant identified at registration ("designated Market Participant"):

(a) JOU maximum physical capacity operating limit;

(b) JOU maximum physical 10-minute response from an off-line state (if a Fast-Start Resource).

(2) The following Offer parameters as submitted by or on behalf of each Market Participant for its JOU share that has registered under the Individual Resource Option must meet the following criteria in order to be accepted as valid offers, otherwise, all Offers related to the Physical JOU Resource will revert to the last valid offer;

(a) The sum of the Maximum Emergency Capacity Operating Limits of each JOU share associated with the Physical JOU Resource must be less than or equal to the Physical JOU Resource maximum physical capacity operating limit.

(3) Commitment of individual JOU shares that have registered under the Individual Resource Option will be evaluated by the Simultaneous Co-optimization Methodology based on the individually submitted Offers for each JOU share;

(4) If committed, each JOU share under the Individual Resource Option will be considered separately for the purposes of dispatch, Flexibility Reserve Products clearing and settlement and the Physical JOU Resource will receive a single Setpoint Target for the purposes of Energy and Flexibility Reserve Products deployment;

(a) If a JOU share is committed by the Market Operator in the DA Market, that JOU share is cleared for Energy based on the submitted Energy Offer Curve and Ramp

Rate and is cleared for Flexibility Reserve Products based on the submitted Flexibility Reserve Products Offers and Ramp Rate;

(b) Each JOU share committed by the Market Operator in the DA Market is eligible to receive a DA Market make whole payment under the same eligibility rules as any other Resource;

(c) In the RTBM, each JOU share is dispatched for Energy based on the submitted Energy Offer Curve, Ramp-Rate-Up and Ramp-Rate-Down and is cleared based on the submitted Flexibility Reserve Products Offers, Ramp-Rate-Up and Ramp-Rate-Down. The Market Operator sends to each Market Participant its independent Setpoint Target and cleared amount(s) of Flexibility Reserve Products for its individual JOU share.

The Market Operator will also, for information purposes, send to the operating Market Participant each Market Participant's independent Dispatch Targets and the sum of these independent Dispatch Targets, and each Market Participant's independent Setpoint Targets and the sum of the Market Participant's independent Setpoint Targets.

If a JOU share is committed by the Market Operator in any RUC process, that individual JOU share is eligible to receive a RUC make whole payment under the same eligibility rules as any other Resource.

Each JOU share will be subject to charges associated with Uninstructed Resource Deviation that exceeds the JOU share Operating Tolerance and Flexibility Reserve Products deployment failure charges based on Setpoint Targets for each JOU and the actual output submitted by each respective Meter Agent for each JOU.

The Meter Agent(s) assigned to the Physical JOU Resource registered under the Individual Resource Option must account for all physical Energy produced and properly reflect this Energy in each individual JOU share Meter Data submittal.

4.2.8 Combined Cycle Resource

Market Participants shall select from one of the four following options regarding submitting Resource Offers for their registered combined cycle Resources, which will be declared during asset registration as described under Sections 6.2 of this Attachment A:

(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; or

(4) A Resource Offer may be submitted for each registered combined cycle configuration, where each configuration represents an operating state of the combined cycle Resource with a distinct set of physical operating characteristics, as dictated by the physical attributes of the combined cycle Resource. The Market Operator will determine the most economic commitment configuration, if requested to do so by the Market Participant as part of the submitted Resource Offer, and once committed, the most economic configuration to transition to for use in both the Day-Ahead Market and Real-Time Balancing Market. Settlement for a combined cycle

Resource submitting offers in this manner will occur in the same manner as any other Resource except for Flexibility Reserve Products during transitions as described under Section 9.2.5 and Section 9.3.4 of this Attachment A. Under this option, Market Participants must define during asset registration the:

(a) Valid configurations, one of which must represent the maximum capacity of the combined cycle Resource;

(b) Valid transitions between configurations as defined in the Market Protocols; and

(c) One or more sets of physical units that can participate in a configuration.

4.3 Interchange Transactions

4.3.1 Import Interchange Transaction Offers

(1) Market Participants may submit offers to sell Energy into the Day-Ahead Market, RTBM, or both, delivered from a source located outside of the Markets+ Footprint. Import Interchange Transaction Offers will be evaluated based on the external source as identified on the e-Tag.

(2) There are two types of Import Interchange Transaction Offers:

(a) A Self-Schedule Offer – Specifies a MW amount that the Market Participant seeks to clear and schedules regardless of the price at the External Interface Settlement Location. If the self-schedule Import Interchange Transaction is submitted for use in the Day-Ahead Market, it will be cleared in the Day-Ahead Market and automatically roll forward as a self-schedule for use in RUC and the RTBM. Any adjustment to the schedule will be settled in the RTBM as a deviation from the Day-Ahead Market schedule. If specified for use in the RTBM only, the self-schedule Import Interchange Transaction will be considered a self-schedule for RUC and RTBM; and

(b) A Economic Offer - Specifies both a MW amount and a minimum dollars per MWh price that the Market Participant is willing to accept if the transaction clears the Day-Ahead Market. Economic Offers are only available for use in the Day-Ahead Market and cannot be submitted for use in the RTBM. Import Interchange Transactions may be submitted up to Offer Cap as described in Attachment A Section 5.3 and are not subject to cost verification. If the transaction clears the Day-Ahead Market, it automatically rolls forward as a self-schedule for use in RUC and RTBM. Any adjustment to the schedule will be settled in the RTBM as a deviation from the Day-Ahead Market schedule.

(3) An Import Interchange Transaction Offer is required to have an associated transmission service reservation(s) from the applicable External Interface to the

sink location identified in the e-Tag within the Markets+ Footprint. Such transmission service shall be obtained in accordance with the Open Access Transmission Tariff(s) of all applicable Transmission Providers.

(4) All Import Interchange Transactions from a source located in Canada shall be deemed to have a point-of-receipt at the U.S./Canada border.

4.3.2 Export Interchange Transaction Bids

(1) Market Participants may submit bids to purchase Energy from the Day-Ahead Market, RTBM, or both, for delivery to a sink located outside of the Markets+ Footprint. Export Interchange Transaction Bids will be evaluated based on the external sink as identified on the e-Tag.

(2) There are two types of Export Interchange Transaction Bids:

(a) A Self-Schedule Bid - Specifies a MW amount that the Market Participant seeks to clear and schedules regardless of the price at the External Interface Settlement Location. If the self-schedule Export Interchange Transaction is submitted for use in the Day-Ahead Market, it will be evaluated in the Day-Ahead Market and cleared awards will automatically roll forward as a self-schedule for use in RUC and the RTBM. Any adjustment to the schedule will be settled in the RTBM as a deviation from the Day-Ahead Market schedule. If specified for use in the RTBM only, the self-schedule Export Interchange Transaction will be considered a self-schedule for RUC and RTBM; and

(b) A Economic Bid - Specifies both a MW amount and a maximum price that the Market Participant is willing to pay if the transaction clears the Day-Ahead Market. Economic Bids are only available for use in the Day-Ahead Market and cannot be submitted for use in the RTBM only. Export Interchange Transactions may be submitted up to Offer Cap as described in Attachment A Section 5.3 and are not subject to cost verification. If the transaction clears the Day-Ahead Market, it automatically rolls forward as a self-schedule for use in RUC and the RTBM. Any adjustment to the

schedule will be settled in the RTBM as a deviation from the Day-Ahead Market schedule.

3) An Export Interchange Transaction Bid is required to have an associated transmission service reservation(s) from the source identified in the e-Tag to the applicable External Interface. Such transmission service shall be obtained in accordance with the Open Access Transmission Tariff(s) of all applicable Transmission Providers.

4) All Export Interchange Transactions to serve load located in Canada shall be deemed to have a point-of-delivery at the U.S./Canada border.

4.3.3 Through Interchange Transactions

(1) Market Participants may submit Through Interchange Transactions in the Day-Ahead Market, RTBM or both, to effect delivery through the Markets+ Footprint of electricity between a source and a sink that are both located outside the Markets+ Footprint. Through Interchange Transactions will be evaluated based on the external source and sink as identified on the e-Tag.

(2) There is one type of Through Interchange Transaction:

Self-Schedule Transaction - Defines a specific MW amount that will be cleared regardless of the price at either of the External Interface Settlement Locations. If submitted for use in the Day-Ahead Market, a self-scheduled Through Interchange Transaction will automatically roll forward as a self-schedule for use in RUC and the RTBM. Any adjustment to the schedule will be settled in the RTBM as a deviation from the Day-Ahead Market schedule. If submitted for use in the RTBM, the self-schedule Through Interchange Transaction will clear in the RTBM and will be considered a self-schedule for use in the RUC.

(3) Through Interchange Transaction is required to have an associated transmission service reservation(s) between the External Interfaces identified on the e-Tag. Such transmission service shall be obtained in accordance with the Open Access Transmission Tariff(s) of all applicable Transmission Providers.

5. Special Rules and Provisions

5.1 Must-Offer Requirement

5.1.1 Day-Ahead Market and Reliability Unit Commitment

Market Participants are required to offer a minimum amount of resource capacity to the Day-Ahead Market. Day-Ahead offers are used for the Day-Ahead market clearing process and also serve as the starting point for the RUC process. A Market Participant's resource capacity is the sum of the offered capacities of Resources with a commitment status of Market, Self, or Reliability Must Run as described in Section 4.1 of this Attachment A. After satisfying the must offer obligation, a Market Participant may offer any remaining energy or capacity to the market at its discretion. Market Participants satisfy this Day-Ahead must offer requirement by meeting the criteria set forth in 5.1.1(A) during non-binding seasons, and the lesser of 5.1.1 (A) or 5.1.1 (B) in binding seasons, as defined in the Resource Adequacy Program. During the binding season, in the event that the calculation of (A) exceeds (B), the capacity amount determined under (B) will act as a ceiling on the Market Participant's must offer requirement, as (B) represents the maximum amount the Market Participant is required to offer to Markets+.

A. Each Market Participant will satisfy the must offer obligation by offering resource capacity greater than or equal to the sum of that Market Participant's (1) load and (2) Flexibility Reserve Products obligations, adjusted by (3) obligations to supply to or rights to receive from the Resource Adequacy Program and adjusted by (4) net position for each Operating Hour based on the following criteria:

   (1) A Market Participant's load for purposes of this section shall be equal to the Market Participant's hourly load forecast as described in Section 7.6 of this Attachment A.

   (2) A Market Participant's hourly Flexibility Reserve Products obligation shall be equal to the sum of that Asset Owner's Short-Term Flex Up and Mid-Term Flex Up obligations as estimated by the Market Operator in accordance with Section 7.5 of this Attachment A.

   (3) A Market Participant's obligation to supply to or right to receive energy from the Resource Adequacy Program is described in the Protocols.

   (4) A Market Participant's net position is described in the Protocols.

(5) The Resource capacity for a Market Participant is reduced by the total Self-Charging MWs of all MSRs registered to that Market Participant for the Operating Hour.

B. Each Market Participant will satisfy the maximum must offer obligation by offering Resource capacity greater than or equal to the Market Participant's (1) Resource Adequacy Program forward showing requirement during a binding season as defined by the Resource Adequacy Program, adjusted by (2) any obligations to further supply to or rights to receive energy from the Resource Adequacy Program, adjusted by (3) net position, and adjusted for (4) day-ahead forecasted fleet performance based on the following criteria:

(1) A Market Participant's forward showing requirement is the quantity of capacity required to demonstrate adequacy for the Resource Adequacy Program for each Operating Day during a binding season.

(2) A Market Participant's obligation to supply or rights to receive energy from the Resource Adequacy Program, is described in the Protocols.

(3) A Market Participant's net position is described in the Protocols.

(4) A Market Participant's adjustment for forecasted day ahead fleet performance is the sum of any forced outages, unplanned unavailability and unplanned change of capacity of Resources registered to the Market Participant for the Operating Hour, and further described in the Protocols.

C. To the extent that a Market Participant does not meet the conditions described in Sections 5.1.1(A) or (B), the Market Participant shall be deemed noncompliant with the must offer obligation for that hour. The Market Operator will assess a penalty amount equal to the product of the shortfall capacity and the associated Day-Ahead Market LMP as described below.

(1) A Market Participant's shortfall capacity for an Operating Hour is equal to the lesser of the difference between the resource capacity and Day-Ahead Market must offer obligation, as described above in Section 5.1.1(A) and (B).

(2) The Must-Offer Penalty LMP is calculated as the average of the Day-Ahead LMP for the Market Participant's Resources in the Operating Hour with the shortfall. If a Market Participant has no registered Resources, then the Markets+ Marginal Energy Component will be used. In no case shall the penalty be less than $0.00.

(3) The Market Operator will distribute any collected penalties for an Operating Hour to Market Participants that are compliant with the Day-Ahead must offer obligation for that Operating Hour, weighted by Resource capacity in excess of the must offer obligation for the Operating Hour.

(a) The Market Operator will distribute any collected penalty revenue for an Operating Hour to Revenue Neutrality Uplift, as described under Section 9.4 of this Attachment A, for any Operating Hour in which no Market Participant with a Resource capacity, as described above in Section 5.1.1(A) and 5.1.1(B), exceeds the must offer obligation for the Operating Hour.

5.1.2 Real-Time Balancing Market

Market Participants are required to offer resource capacity to the RTBM as described below. A Market Participant's resource capacity is the sum of Resources offered with a commitment status of Market, Self, or Reliability Must Run as described in Section 4.1 of this Attachment A. After satisfying the must offer obligation, a Market Participant may offer any remaining energy or capacity to the market at its discretion. Market Participants satisfy this requirement by meeting the criteria set forth in 5.1.2(A) or (B) below:

(A) Each Market Participant will satisfy the must offer obligation in an Operating Hour by offering Resource capacity greater than or equal to the sum of (1) cleared Day-Ahead Market Energy, (2) cleared Flexibility Reserve Products, and (3) incremental Market Commitments from the RUC process, adjusted by (4) obligations to supply to or rights to receive from the Resource Adequacy Program and adjusted by (5) deviation in net position.

(1) A Market Participant's cleared Day-Ahead Market Energy is the sum of Energy cleared in the Day-Ahead Market for all Resources registered to the Market Participant for the Operating Hour.

(2) A Market Participant's cleared Day-Ahead Market Flexibility Reserve Products is the sum of Short-Term Flex Up and Mid-Term Flex Up cleared in the Day-Ahead Market for all Resources registered to the Market Participant for the Operating Hour.

(3) A Market Participant's incremental commitments from the RUC process is the sum of energy dispatch associated with incremental commitments from the initial RUC process for all Resources registered to the Market Participant for the Operating Hour, further described in the Protocols.

(4) A Market Participant's obligation to supply energy to or right to receive energy from the Resource Adequacy Program is described in the Protocols.

(5) A Market Participant's deviation in net position is determined by comparing the final net position to the net position that cleared in the Day-Ahead Market for the Operating Hour and further described in the Protocols.

(6) The resource capacity of a Market Participant is reduced by the total Self-Charging MWs of all MSRs registered to that Market Participant for the Operating Hour.

During the binding season each Market Participant will satisfy the must offer obligation by offering Resources greater than or equal to the higher of the Day-Ahead compliance amount described in Section 5.1.1(B) and the Real-Time must offer amount described in Section 5.1.2(A) (1, 2 & 3), adjusted by (1) further obligation to supply energy to or receive energy from the Resource Adequacy Program not accounted for in the Day-Ahead Market, adjusted by (2) net position not accounted for in the Day-Ahead Market and adjusted by (3) fleet performance changes not accounted for in the Day-Ahead Market.

During a non-binding season each Market Participant will satisfy the must offer obligation by offering Resources during the non-binding season greater than or equal to the Real-Time must offer amount described in Section 5.1.2(A) (1, 2 & 3), adjusted by (2) net position not accounted for in the Day-Ahead Market and adjusted by three (3) fleet performance changes not accounted for in the Day-Ahead Market.

(1) A Market Participant's obligation to supply energy to or receive energy from the Resource Adequacy is described in the Protocols.

(2) A Market Participant's net position not accounted for in the Day-Ahead Market are further described in the Protocols.

(3) A Market Participant's adjustment for fleet performance changes not accounted for in the Day-Ahead Market is the sum of unplanned unavailability or reduction of capacity of Resources registered to the Market Participant for the Operating Hour compared to the unplanned unavailability or reduction of capacity of the Market Participant for the Operating Hour offered into the Day-Ahead Market and further described in the Protocols.

C. A Market Participant not meeting the conditions described in Sections 5.1.2(A) or (B) , the Market Participant shall be deemed noncompliant with the must offer obligation for that

Operating Hour. The Market Operator will assess a penalty amount equal to the product of the shortfall capacity and the associated RTBM LMP as described below.

(1) A Market Participant's shortfall capacity for the Operating Hour is equal to the lesser of the difference between the resource capacity and Real Time Balancing Market must offer obligation, as described above in Section 5.1.2 (A) and (B).

(2) The Must-Offer Penalty LMP is calculated as the average of the RTBM LMP for the Market Participant's Resources in the Operating Hour with the shortfall. . If a Market Participant has no registered Resources, then the Markets+ Marginal Energy Component will be used. In no case shall the penalty be less than $0.00

(3) The Market Operator will distribute any collected penalties for an Operating Hour in the RTBM to Market Participants deemed compliant with the must offer obligation for that Operating Hour, weighted by resource capacity in excess of the must offer obligation for the Operating Hour.

(a) The Market Operator will distribute any collected penalty revenue for an Operating Hour to Revenue Neutrality Uplift, as described under Section 9.4 of this Attachment A, for any Operating Hour in which no Market Participant with a Resource capacity, as described above in Section 5.1.2(A) and 5.1.2(B), exceeds the must offer obligation for the Operating Hour.

5.3 Offer Caps and Floors

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

(1) Safety-net Energy Offer Cap = $1,000/MWh; Energy Offers greater than $1,000/MWh are subject to Section of Attachment B of this Tariff.

(2) Virtual Energy Offer Cap = $2,000/MWh;

(3) Import/Export Transaction Offer Cap = $2,000/MWh;

(4) Energy Offer Floor = Negative $150/MWh;

(5) Start-Up Offer Floor = $0;

(6) No-Load Offer Floor = $0.

(7) Flexibility Reserve Products Floor = $0/MWh

(8) Flexibility Reserve Products Cap = $1,000/MWh

In addition to these Offer caps and floors, submission of Offers may be limited by the requirements of Attachment B of this Tariff.

5.4 Virtual Transactions Implementation, Suspension, and Mitigation

Virtual Transactions (both demand bid and Resource offer) and the settlement thereof will not be implemented earlier than six (6) months after implementation of Markets+, and will not be implemented during the summer season. Virtual transactions are not allowed at Markets+ boundary interface settlement locations.

The Market Operator may suspend Virtual Transactions in its sole discretion. In exercising that discretion, the Market Operator will consider whether those Virtual Transactions remain a cost effective tool aiding price convergence.

The Market Operator's decision to suspend Virtual Transactions is subject to review by the Market Monitor.

Virtual Transactions can be suspended as long as necessary at the Market Participant level, at individual locations or groups of locations, or market-wide to identify and resolve the underlying cause. The Market Operator may restrict Virtual Transactions to physical Settlement Locations only.

When the Market Operator suspends Virtual Transactions under this Section 5.4, this suspension and the underlying cause identified by the Market Operator will be posted as soon as practical on the Marketplace Portal, no later than the close of the Day-Ahead Market.

If a determination is made, as specified in Section X of Attachment C, that excessive divergence exists and the divergence is the result of the Virtual Transactions of one or more Market Participants, the Market Operator will impose mitigation measures. The mitigation measures should restrict the Market Participants that caused the divergence from submitting any Virtual Energy Bids or Virtual Energy Offers at the Settlement Locations where the Market Participant's Virtual Energy Bids or Virtual Energy Offers caused the excessive divergence.

6. Market Participant Obligations

Market Participants must comply with the requirements and procedures described in the Tariff and the Markets+ Protocols.

6.1 Service Agreement and Application

Each Market Participant must execute the service agreement in Attachment E or a FERC approved non-conforming version thereof. If the Market Participant fails or refuses to execute this service agreement, the Market Operator will file an unexecuted agreement with FERC.

Applications for a Market Participant to provide services in Markets+ must be submitted to the Market Operator prior to the expected date of participation. Applications must conform to the procedures specified in the Markets+ Protocols and may be rejected if not complete. New Market Participants must follow the model update timing requirements in the Markets+ Protocols.

As part of the application process, Market Participants must register all Resources and load, including Non-Conforming Load and Demand Response Load, with the Market Operator as specified in Section 6.2.

6.2 Asset Registration

(1) As part of Resource registration, Market Participants must specify whether settlement Meter Data will be submitted on a gross basis or net basis, where gross Meter Data does not include reductions for auxiliary load and net Meter Data is gross Meter Data reduced by auxiliary load.

(a) Both Non-Conforming Load and Demand Response Load may only be associated with a single Price Node, except that Non-Conforming Load and Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes.

(2) Market Participants may elect to define a single Settlement Location that aggregates multiple Meter Data Submittal Locations associated with their load assets. Such a Settlement Location is used for settlements purposes only and the Meter Data Submittal Locations being aggregated must be within a single Settlement Area.

(3) Market Participants registering Jointly Owned Units must choose an option described below.

(a) Individual Resource Option

i. Each Market Participant's share is modeled as a separate Resource for the purposes of commitment and each Resource may be committed independent of the other Resource shares.

ii. A Resource registered as a Multi-Configuration Resource may not register as a Jointly Owned Unit under the individual Resource option.

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

iv. Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the Jointly Owned Unit maximum physical capacity operating limit and the maximum physical ten (10) minute response from an off-line state.

(b) Combined Interest Resource Option

i. A Combined Interest Resource is registered as a single resource for market operation under a single Market Participant.

ii. A Resource registered as a Multi-Configuration Resource may not register as a Jointly Owned Unit under the Combined Interest Resource option.

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

iv. A Market Participant registering a Resource with combined interest shall provide the individual interest percent share by Market Participant. Each individual interest must have contractual rights to or financial obligations for that Resource.

v. Credits and charges for a Combined Interest Resource are allocated using the percentage of submitted interest share.

(4) Market Participants may modify their asset registration in accordance with the asset registration procedures.

(5) A Market Participant must register all its load within the Markets+ Footprint. Failure or refusal to register a load will result in the Market Operator filing an unexecuted version of the service agreement for that load with FERC under the name of the Market Participant.

(6) A Market Participant must register all its generation within the Markets+ Footprint capable of producing and maintaining a response of at least 0.1 megawatt (MW) for a continuous duration of sixty (60) minutes and capable of injecting to the transmission system unless otherwise included in a broader resource aggregation. Resources not capable of producing and maintaining a response of at least 0.1 MW for a continuous duration of sixty (60) minutes are not eligible to register. Behind-The-Meter Generation less than 10 MWs may, but is not required, to register. Additionally, Behind-The-Meter Resources greater than ten (10) MW that do not operate synchronous to the grid or are not capable of injection into the transmission system or are included as part of a larger resource aggregation, including demand response, are not required to register. All other Resources must register.

(a) Market Participant's failure or refusal to register a Resource within the Markets+ Footprint will result in the Market Operator filing an unexecuted version of the

service agreement for that Resource with FERC under the name of the Market Participant.

(b) In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility, such registration will not require the Qualifying Facility to participate in Markets+ or subject the Qualifying Facility to any charges or payments related to Markets+. Any Markets+ charges or payments associated with the output of the Qualifying Facility will be allocated to the Market Participant representing the host utility purchasing the output of the Qualifying Facility under PURPA, and the Market Participant will be provided the settlement data required to verify the settlement charges and payments.

(7) For a Market Participant to offer an External Resource in Markets+, the Market Participant must use an External Resource Pseudo-Tie. The Market Participant registering the External Resource will be responsible for registering and performing all responsibilities that are required of Resources in Markets+.

(8) A Market Participant attempting to register a Demand Response Resource in Markets+ must not register a Demand Response Resource that is precluded under applicable laws or regulations from participation in Markets+.

A Market Participant must include in its application and registration a certification that its Demand Response Resource's participation in Markets+ is not precluded under applicable laws or regulations. An ARC wishing to offer Demand Response Load in the form of a Demand Response Resource on behalf of one or more retail customers must also include in its application and registration a certification that participation of each retail customer is either: (1) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (2) affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year.

Demand Response Resources must meet all application, registration and technical requirements applicable to Markets+. The Market Operator is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that

the Market Participant has included such a certification in its application materials, if applicable. The Market Operator is not liable or responsible for Market Participants participating in Markets+ in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

A. For purposes of participation in Markets+, an ARC may aggregate a Demand Response Load associated with a Dispatchable Demand Response Load Settlement Location of: (1) End-use retail customers of utilities that distributed more than 4 million MW hours ("MWh") in the previous fiscal year, unless precluded by the laws or regulations of the relevant electric retail regulatory authority including state-approved retail tariff(s); and (2) End-use retail customers of utilities that distributed 4 million MWh or less in the previous fiscal year, where the relevant electric retail regulatory authority, including any state-approved retail tariff(s), affirmatively permits such customer's demand response to be offered into Markets+ by an ARC. ARCs shall be treated comparably to other Market Participants offering Resources in Markets+.

The Market Operator is not liable or responsible for Market Participants participating in Markets+ in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

Aggregations pursuant to this section shall be subject to the following requirements:

A. End-use customers may be aggregated into a single Dispatchable Demand Response Resource. The Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes, provided that such aggregated Price Node is served by the same retail provider;
B. All end-use customers in an aggregation shall be specifically identified.
C. For a Dispatchable Demand Response Resource of an ARC that chooses to measure demand reductions using the calculated real-time response methodology, a single hourly baseline for each registered Resource shall be used to determine settlements.

(9) Any non-ARC Market Participant offering a Dispatchable Demand Response Resource associated with one or more retail or wholesale customers in Markets+ must satisfy all applicable registration and certification requirements.

Aggregations pursuant to this section shall be subject to the following requirements:

(a) Retail or Wholesale customers may be aggregated into a single Dispatchable Demand Response Resource. The associated Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes, provided that such aggregated Price Node is served by the same retail or wholesale provider;

(b) All retail or wholesale customers in an aggregation shall be specifically identified.

(c) For a Dispatchable Demand Response Resource of an aggregator that chooses to measure demand reductions using the calculated real-time response methodology, a single hourly baseline for each registered Resource shall be used to determine settlements.

(10) All Variable Energy Resources in the Markets+ Footprint, including Variable Energy Resources for which the Market Operator, must be registered as a Dispatchable Variable Energy Resource except for (1) a Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility or (2) a Resource having a primary fuel source of run of the river hydro-electric that is incapable of following Dispatch Targets. A Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Market Operator and will be subject to the Dispatchable Variable Energy Resource market rules including Uninstructed Resource Deviation charges.

(11) A Market Participant registering an ESR must register as follows:

(a) An ESR of at least 0.1 MW that is capable of transmission system injection or directly connected to the Markets+ Footprint must register.

(b) A Market Participant registering an ESR that is not required to register under this Tariff, or a Market Participant registering an ESR that intends to participate in both wholesale and retail markets, must meet all application, registration and technical requirements applicable to Markets+. ESRs not directly connected to the Markets+ Footprint must specify, through Meter Data submittal, all withdrawals and injections subject to wholesale settlements. Withdrawals are subject to wholesale settlements when the Energy withdrawn is later injected back to the Markets+

Footprint. If an ESR is behind-the-meter of another registered Resource or load, the Meter Agent for the ESR is responsible for coordinating any wholesale withdrawal or injection to the Markets+ Footprint with the Meter Agent for the Resource or load so that the ESR activity is removed from the Resource or load Meter Data.

(12) Market Participants must submit registration information in accordance with Section 6.9 of this Tariff.

6.3 Non-Participating Entity Registration

In the event an entity within a participating Balancing Authority Area chooses not to register its load or Resources in Markets+, the responsibility for registering those assets will be with the participating host Balancing Authority. The Market Operator will not be a party to any agreement between the host Balancing Authority and the non-participating entity. Failure or refusal to register a load or Resource will result in the Market Operator filing an unexecuted version of the service agreement in Attachment E of this Tariff for that Resource with FERC under the name of the Market Participant representing the participating host Balancing Authority.

6.4 Market Manipulation

Market Participants must not engage in any market manipulation activities, as directed in 18 C.F.R. § 1c.2.

6.5 Commitment and Dispatch

Market Participants shall, where applicable:

(a) Follow the Market Operator's Dispatch Targets and Market Commitment instructions;

(b) Update Offer parameters to reflect changes to Resource availability and capability throughout the Operating Day;

(c) Report changes to Ancillary Service Plans resulting from changes in Resource availability to the Market Operator; and

(d) Abide by the procedures set forth in the Markets+ Protocols.

6.6 Provision of Load and Generation Data

Market Participants must designate a Meter Agent as part of the application process. A Market Participant may perform the Meter Agent function on its own behalf or designate any qualified entity to perform the Meter Agent function. Market Participants that will act as their own Meter Agent must complete Exhibit A of the Meter Agent Services Agreement in Attachment G. If a Market Participant chooses to engage a third party Meter Agent, then the Market Participant and the Meter Agent must execute the Meter Agent Services Agreement and Exhibit A in Attachment G.

Market Participants, or their designated Meter Agents, shall exercise due diligence in submitting to the Market Operator accurate data for each Operating Day, or estimates where actual data is not available. Such submissions shall represent the actual Resource output and load consumption and be submitted in accordance with the settlement timelines as described in the Markets+ Protocols. Resource output is submitted on either a gross or net basis as specified during market registration.

6.7 Provision of Wind and Solar Forecast Data

Market Participants must submit geographic data and wind turbine availability data for each wind-powered Variable Energy Resource to the Market Operator.

Market Participants must submit geographic data and facility data for each solar-powered Variable Energy Resource to the Market Operator.

6.9 Registration Information, Resource Offers, and Outages

In submitting registration information, Resource Offers, and outage information, Market Participants must include information, parameters, and limitations that reflect the Market Participant's reasonable assessment of a Resource's capabilities to provide services outlined in this Tariff. A Market Participant's reasonable assessment may be informed by environmental and recreational limitations, operating constraints, operating permits or licenses, applicable law, contractual limitations or requirements, actions and instructions by applicable government agencies, and Good Utility Practice among other factors. The parameters in a Resource Offer must be within the Resource's registered parameters unless otherwise required by extraordinary circumstances. When requested by the Market Monitor, the Market Participants must provide supporting explanation for constraints, limitations, outages, and registration information.

7. Market Operator Obligations

The Market Operator shall comply with the requirements and procedures pertaining to Markets+ described in this Tariff.

7.1 Markets+ Protocols

The Market Operator shall prepare, maintain and update the Markets+ Protocols consistent with the Markets+ Tariff. The Markets+ Protocols shall be posted on the Market Operator's website.

7.2 Trading Hub Establishment and Modification

The Market Operator shall review the proposed establishment, modification or termination of a Trading Hub with stakeholders. The Markets+ Participants Executive Committee will consider the proposed establishment, modification or termination of a Trading Hub and will provide a recommendation to the Markets+ Independent Panel for review and approval. Updating an existing Trading Hub to reflect a terminated Pnode due to the termination of the load or generation at that Pnode is not considered a modification and does not require consideration by the Markets+ Participants Executive Committee for review and approval by the Markets+ Independent Panel.

The Market Operator must establish and maintain at least one Trading Hub. An existing Trading Hub may be modified or terminated only in the event that the LMP at that Trading Hub can no longer be calculated. The Market Operator shall post any approved establishment of a Trading Hub at least forty-five (45) Calendar Days prior to the proposed effective date. The Market Operator shall post any modification or termination of a Trading Hub within thirty (30) Calendar Days after it has determined that there is a need for modification or termination.

The Market Operator shall use the following criteria to establish Trading Hubs:

(1) Each Trading Hub shall contain a sufficient number of nodes to ensure that a Trading Hub LMP can be calculated for that Trading Hub at all times;

(2) Each Trading Hub shall contain a sufficient number of nodes to ensure that the unavailability of, or an adjacent line outage to, any one node or set of nodes would have only a minor impact on the Trading Hub LMP;

(3) Each Trading Hub shall consist of nodes with a relatively high rate of service availability;

(4) Each Trading Hub shall consist of nodes among which Transmission Service is relatively unconstrained; and

(5) A Trading Hub shall not encompass the combined loads and Resources of a single vertically-integrated utility into a single Settlement Location.

7.3 Reserve Zone Establishment

(1) The Market Operator shall identify the need for Reserve Zones within the SPP Markets+ Footprint through Reserve Zone studies that identify constrained areas that may require a minimum amount of Flexibility Reserve Products procurement and/or that may be limited to a maximum amount of Flexibility Reserve Products procurement to ensure system-wide procurement of Flexibility Reserve Products is deliverable when deployed.

(a) Reserve Zone studies will be conducted semi-annually and the Reserve Zone configuration will be made effective November 1 and May 1 of each year, with the study results posted on the Market Operator's website no later than thirty (30) days prior to each effective date. Normal Transmission System topology will be used for the study along with selected, approved outages. All Resources and loads in the SPP Markets+ Footprint will be evaluated.

(b) In order to ensure deliverability of reserves, the most likely constrained transmission facilities must be identified. Monitored constraints will be identified through analysis of historical congestion activity, planned transmission and Resource outages, and forecasted system demands and Resources.

(c) Once a final set of transmission constraints is identified, the Reserve Zones are established by grouping the PNodes, based on similar impact on all of the remaining transmission constraints. The groups of PNodes represent the Reserve Zones. Each PNode will be placed into only one Reserve Zone.

(2) The Market Operator may add or reconfigure a Reserve Zone between semi-annual updates to address significant changes in system conditions that would cause adverse impacts to Flexibility Reserve Products deliverability absent the Reserve Zone addition or reconfiguration. The Market Operator will notify the Market Participants of any resulting changes made to the Reserve Zones and will post the results on the Market Operator's website no less than two (2) Business Days prior to becoming effective.

7.4 Flexibility Reserve and Instantaneous Load Capacity Requirements

The Market Operator shall calculate the amount of Flexibility Reserve Products required for the Operating Day, on both a Markets+ Footprint and Reserve Zone basis. In addition, the Market Operator shall calculate the amount of Instantaneous Load Capacity required for the Operating Day on a Markets+ Footprint basis in order to ensure that load can be serviced in real-time. The Market Operator shall, on a daily basis:

(1) Calculate the hourly Flexibility Reserve Products requirements on a Markets+ Footprint basis and post such results by 0630 hours PPT Day-Ahead for use in the Day-Ahead Market, RUC and RTBM;

(2) Calculate the minimum and maximum Flexibility Reserve Products requirements for deployment in the up direction and for deployment of Flexibility Reserve Products in the down direction for each Reserve Zone.

(3) Estimate each Market Participant's Flexibility Reserve Products obligation by Market Participant in each Reserve Zone and provide such information to Market Participants by 0630 hours PPT Day-Ahead. The Market Operator shall calculate such estimates by multiplying the Markets+ Footprint Flexibility Reserve Products requirements calculated in (1) above by the Market Operator's estimate of each Market Participant's load in each Reserve Zone divided by the Market Operator's estimate of Markets+ Footprint load;

(4) The Market Operator may increase Flexibility Reserve Products requirements for the RUC and RTBM above the requirements used in the Day-Ahead Market to cover the increased risk of the supply availability of Uncommitted Import Interchange Transactions.

(a) To the extent that the Market Operator increases the Flexibility Reserve Products requirements, the increased costs associated with such increased requirements shall be collected from all Market Participants with cleared Uncommitted Import Interchange Transactions on a pro-rata basis based upon the MW levels of the imports cleared in the Day-Ahead Market.

(b) The Market Operator may also make modifications to the Reserve Zone minimums and maximums due to unexpected system condition changes following the close of the Day-Ahead Market.

(5) Calculate the hourly Instantaneous Load Capacity requirements for an interval on a Markets+ Footprint basis for use in the Day-Ahead Market and RUC processes in accordance with the calculation procedures specified in the Markets+ Protocols.

7.5 Forecasting

(1) The Market Operator shall develop load forecasts for the Markets+ Footprint for use in the RUC processes and RTBM. The Market Operator shall adjust such forecasts in order to remove average system losses prior to execution of the market applications in order for the dispatch to properly reflect the treatment of marginal losses.

(2) The Market Operator shall develop hourly forecasts for wind and solar-powered Variable Energy Resources for use in the RUC processes and Dispatch Interval forecasts for wind and solar-powered Variable Energy Resources for use in the RTBM as follows:

(a) The Market Operator shall use an industry standard wind generation output forecast software tool.

(b) To develop the forecasts, the software tool uses estimates of wind flow pertaining to the wind powered Variable Energy Resource location using regional atmospheric weather condition predictions obtained from weather forecasting services and the geographic data provided. In order to obtain increased accuracy, the estimates of wind flow are adjusted using the site-specific meteorological and geographical data provided.

(c) To develop the site-specific wind powered Variable Energy Resource output forecast, the site-specific estimates of wind flow are applied to either (i) wind flow versus power output curves developed from historical output data or (ii) the manufacturer's wind flow versus power output curve if there is no historical data available, adjusted as required to account for turbine availability data.

7.6 Markets+ Operations

The Market Operator shall evaluate Offers and Bids submitted by Market Participants to ensure sufficient Resources are committed to meet the Markets+ Footprint projected load and Flexibility Reserve Products requirements for the upcoming Operating Day. The Market Operator shall clear Energy and Flexibility Reserve Products in the Day-Ahead Market using the Simultaneous Co-optimization Methodology.

The Market Operator shall continuously evaluate Offers to ensure sufficient Resources are committed to meet the Markets+ Footprint projected load and Flexibility Reserve Products requirements throughout the Operating Day. The Market Operator shall dispatch Energy and clear Flexibility Reserve Products on Resources in the RTBM using the Simultaneous Co-optimization Methodology.

7.6.1 Simultaneous Co-optimization Methodology

The Simultaneous Co-optimization Methodology produces both a dispatch solution and a pricing solution. The dispatch solution and pricing solution are executed independent of each other. The MW quantities used in settlements for the dispatch and clearing of Energy result from the dispatch solution. Except where specified as DLMP, prices used in settlements result from the pricing solution and will be specified as LMP, MCC, MCP, MEC, and MLC. The DLMP results from the dispatch solution. The differences between the dispatch solution and the pricing solution are:

(1) Dispatch solution

(a) Co-optimization of Energy and Flexibility Reserve Products is based on the Bids, Energy Offers, and Flexibility Reserve Product Offers submitted by the Market Participants.

(2) Pricing solution

(a) For non-FSRs, co-optimization of Energy is based on the Energy Offers and Bids submitted by the Market Participants.

(b) For FSRs committed by the Market Operator, including FSRs committed at the request of a local transmission operator, but not including self-committed FSRs, the Market Operator calculates a Composite Energy Offer for use in the co-optimization of Energy. The Composite Energy Offer will be calculated and applied as follows:

(i) The Market Operator calculates a Composite Energy Offer for an FSR by modifying each price point on the Energy Offer Curve for each market interval of the Minimum Run Time by adding amortized start-up and no-load costs. For FSRs that are MSRs, the composite Energy Offer applies only to the discharge portion of the Energy Offer curve.

1. The commitment costs (i.e. start-up cost and no-load cost) in effect at the time of the commitment are amortized over the Maximum Economic Capacity Operating Limit and the Minimum Run Time.

a. The start-up cost added to each breakpoint of the Energy Offer Curve is calculated by dividing the Start-Up Offer by the Maximum Economic Capacity Operating Limit and by the Minimum Run Time rounded up to the nearest interval.

b. The no-load cost added to each breakpoint of the Energy Offer Curve is calculated by dividing the No-Load Offer by the Maximum Economic Capacity Operating Limit and by the ratio of the number of intervals needed to meet the Minimum Run Time to the number of intervals in an hour.

The application of the composite begins with the commitment interval and extends through the Minimum Run Time.

(a) In addition to dispatchable Bids and Offers, FSRs committed by the Market Operator or local transmission operator, but not including self-committed FSRs, will have their minimum operating limit relaxed to 0 MW.

Mitigation measures for Energy Offers and Flexibility Reserve Product Offers will be performed in the pricing solution. An FSR's composite Energy Offer Curve will be subject to the Energy offer cap.

7.7 Violation Relaxation Limit Reporting

Each year, prior to November 1, the Market Operator will provide analysis as well as a set of proposed Violation Relaxation Limits ("VRLs") for review by the applicable working groups and committees as described in the Markets+ Protocols. Each year by November 1, VRLs and their associated values shall be reviewed and approved by the Markets+ Independent Panel. Any changes to the VRLs or associated values must be approved by FERC prior to their implementation. The most recent FERC approved VRLs and their associated values are listed in Addendum 1 to this Attachment A.

7.8 Markets+ Pricing

The Market Operator shall calculate Day-Ahead Market and RTBM LMPs for Energy at each Settlement Location. The Market Operator shall calculate the Market Clearing Prices ("MCPs") for Flexibility Reserve Products for the Day-Ahead Market and RTBM. In certain situations, enforcing constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, the Market Operator must apply VRLs.

7.8.1 Price Corrections

There may be instances in which Software Errors and/or Data Errors affect the prices in a manner that is inconsistent with economic efficiency. If such an instance occurs, price corrections in the Day-Ahead and Real-Time Balancing Markets may be performed in accordance with Section 7.9.1 of this Attachment A.

(1) The Market Operator, in its sole discretion, may make LMP and MCP corrections, and such corrections shall be made in accordance with this Section 7.9.1. Such price corrections may only be performed if the underlying causes result in a significant Day-Ahead or Real-Time Balancing Market impact. In the exercise of its discretion pursuant to this Section 7.9.1, the Market Operator may consider all relevant facts, including, but not limited to, the degree of the economic impact to the market results in terms of production cost. For purposes of this section, "production cost" is defined as the settlement cost for the market and can be calculated as the sum of the cleared MW * LMP plus cleared OR * MCP plus Start-Up and No-Load costs for all Resources.

(2) If the Market Operator, in its sole discretion, determines that an error requiring correction has occurred, the Market Operator shall address such errors in accordance with the following procedures:

(a) The Market Operator shall notify Market Participants of the contemplated price correction.

(b) If the Market Operator provides the notification described in (2)(a) later than 23:59 hours PPT five (5) calendar days following the Operating Day

in which the LMPs and MCPs would be affected by the contemplated price correction, the Market Operator shall request Commission approval prior to making the price correction.

(c) If the Market Operator performs a price correction for the Day-Ahead Market, it shall recalculate LMPs, MCPs, and Day-Ahead Market cleared quantities in a manner that reflects, as closely as practicable, the LMPs and MCPs that would have resulted but for the relevant Software Error or Data Error while maintaining the original Day-Ahead Market unit commitment. The Market Operator shall perform any necessary Resettlement using the recalculated Day-Ahead Market results. Such recalculated Day-Ahead Market results shall be provided to Market Participants in the same manner as the original Day-Ahead Market results determined in the ordinary course of business.

(d) If the Market Operator performs a price correction for the RTBM, it shall recalculate LMPs and MCPs for the RTBM in a manner that reflects, as closely as practicable, the LMPs and MCPs that would have resulted but for the relevant Software Error or Data Error and shall perform any necessary Resettlement using these recalculated values. Such recalculated LMPs and MCPs shall be provided to Market Participants in the same manner as LMPs and MCPs determined in the ordinary course of business. Compensation to Market Participants in connection with recalculated prices in the RTBM shall be as follows:

(i) For instances where the recalculated RTBM LMP is less than a Resource's Energy Offer Curve price, compensation shall be as described under Section 7.9.1(1) of this Attachment A;

(ii) For instances where a Resource's recalculated RTBM LMP is greater than the Day-Ahead Market LMP and the Market Participant is buying back its Day-Ahead Market position as a result of a Dispatch Instruction, compensation shall be as described under Section 7.9.1(2) of this Attachment A except that the MW amount eligible for compensation shall be equal to the difference between

the Resource's Day-Ahead Market MW position and the greater of (1) that Resource's actual MW output in the Dispatch Interval or (2) the Resource's average Setpoint Target in the Dispatch Interval;

(iii) For instances where a Resource's recalculated RTBM Operating Reserve product MCP is greater than the Day-Ahead Market Operating Reserve product MCP and the Market Participant is buying back its Day-Ahead Market Flexibility Reserve Product position resulting from the Market Operator clearing all or a portion of that Flex on a different Resource in the market solution.

7.9 Markets+ Settlements

For both the Day-Ahead Market and the RTBM, the Market Operator shall calculate Energy and Flexibility Reserve Products settlement quantities at each Settlement Location, calculate charges and payments associated with the provision of Energy and Flexibility Reserve Products based upon the settlement quantities and the associated LMPs and MCPs for each Market Participant and render invoices detailing net charges or payments associated with provision of Energy and Flexibility Reserve Products.

7.10 Release of Offer Curve Data

The Market Operator will release data on all Day-Ahead Offers and Bids, RTBM Energy Offer Curves and Flexibility Reserve Products ninety (90) calendar days after the day for which they were submitted. Such information released by the Market Operator will not be provided by Settlement Location or include the identity of the Market Participant, Resource or load.

7.11 Market Transmission Use

A. General

The Market Operator will calculate, collect, and distribute Market Transmission Use (MTU) charges. Markets+ Transmission Service Providers (MTSP) participating in the Markets+ footprint will be eligible for compensation for transmission capacity used in the Market. Compensation will be calculated and distributed through a rate charged to Market Participants for reduced capacity that would otherwise be available as Short-Term Firm and Non-firm Point-to-Point and reduced demand for those sales.

MTU Charges shall be assessed to Market Participants based on total megawatt hours of generation and load, including imports and exports, cleared in the Day-Ahead Market activities, and to Market Participants with generation, load, import, and exported megawatt hours settled through Real-Time Balancing Market activities.

B. Rate Formula

Annually, the Market Operator will determine the MTU Rate for each rate year as described in Appendix 2 of this Attachment A.

C. Market Transmission Use Charges for Market Activity in the Real-Time Balancing Market (RTBM)

The Market Participant shall pay a Market Transmission Use (MTU) Charge, which shall be determined in Real-Time Balancing Market (RTBM) settlement activities by multiplying its RTBM megawatt hours for all market activities (Generation, Load, Imports, Exports, and any Virtual activities) by the applicable Region-Wide Market Transmission Use Rate (RWMTURt) specified in Appendix 2 of this Attachment A.

D. Market Transmission Use Revenue from Real Time Balancing Market Settlement

Payments received by the Market Operator for Market Transmission Use will be distributed to the Markets+ Transmission Service Providers whose Markets+ Transmission Service Provider's Revenue Recovery Amount (MTSPRRA) is included in the approved Region-Wide Revenue Recovery Amount (RWRRA) used as the numerator for the Region-Wide Market Transmission Use Rate as described in Appendix 2 of this Attachment A.

E. Market Transmission Use Revenue Distribution from Real Time Balancing Market Settlement

The Market Operator shall distribute revenues it collects for Market Transmission Use Charges to each MTSP whose Markets+ Transmission Service Provider Revenue Recovery Amount (MTSPRRA) is included in the approved Region-Wide Revenue Recovery Amount (RWRRA) for the Region-Wide Market Transmission Use Rate as described in Appendix 2 to this Attachment A in proportion to the MTSP's respective share of the RWRRA, as adjusted in accordance Section F. below.

F. Market Transmission Use Revenue Crediting and Impacts to Future Year's Recovery

In calculating the current rate year's Markets+ Transmission Service Provider Revenue Recovery Amount (MTSPRRA) for MTU, the Transmission Service Provider will net the under/over recovery of the prior year's MTU revenue, compared to the prior year's MTSPRRA amount, (defined as Markets+ Transmission Service Provider's Prior-Year Market Transmission Use Offset (MTSPPYMO)) against the current year's MTSPRRA amount for MTU recovery. Should prior calendar year's MTSPPYMO being credited against the current year's MTSPRRA reduce current year's MTSPRRA to a negative amount, the current year's MTSPRRA will be set equal to zero, as a floor, and the remaining balance of any prior calendar year's MTSPPYMO not being captured will roll forward to the netting process in determining the following year's allowable MTSPRRA (defined as MTSP's Carryover Market Transmission Use Offset (MTSPPYMCO)). Each Rate Year's MTSPRRA will be netted against any MTSPPYMO and MTSPPYMCO amounts. This carryover process would continue until the Rate Year MTSPRRA remains above zero after all carryover amounts are realized.

7.12 Transparency Reporting Requirements

The following reports shall be compiled by the Market Operator monthly and posted on a publicly-accessible portion of its website, within the time frame specified for each report.

7.12.1 Zonal Uplift Report

Within twenty (20) calendar days of the end of each month, a report of uplift categories, paid in dollars, and categorized by Settlement Area and uplift category shall be compiled and posted. Uplift categories reported, broken out by day, will include: Day-Ahead Make Whole Payment Amount, Reliability Unit Commitment Make Whole Payment Amount, real-time Out-Of-Merit Amount, and Flexibility Reserve Products Amounts. If any Settlement Area has fewer than four Resources, it may be aggregated with one or more neighboring Settlement Areas until each aggregated zone contains at least four Resources, and reported collectively.

7.12.2 Resource-Specific Uplift Report

Within ninety (90) calendar days of the end of each month, a report of the total amount of uplift paid in dollars aggregated across the month by Resource shall be compiled and posted. The report shall include the following uplift categories: Day-Ahead Make Whole Payment Amount, Reliability Unit Commitment Make Whole Payment Amount, real-time Out-of-Merit Amount, and Flexibility Reserve Products Amounts.

7.12.3 Operator-Initiated Commitment Report

Within thirty (30) calendar days of the end of each month, a report of each operator-initiated commitment, listing the size of the commitment, Settlement Area, commitment reason, and commitment start time shall be compiled and posted. All commitments that are made for a reason other than to minimize the total production cost of serving load will be posted, including those made under the RUC processes.

7.13 Markets+ Participation Readiness

The Market Operator shall validate each Market Participant's ability to provide services for which the Market Participant has registered in Markets+. Such validation shall include verification that the Market Participant has met the technical and communications requirements specified in the Markets+ Protocols and has met the credit requirements specified under Attachment H of this Tariff.

7.14 Markets+ Counterparty

The Markets+ Counterparty settles, collects and distributes all charges in Markets+, and is the contracting party, as a principal and not as an agent, with each Market Participant for that Market Participant's Markets+ agreements and transactions in the Day-Ahead Market and Real-Time Balancing Market. Notwithstanding the above, the Markets+ Counterparty shall not be a contracting party when Market Participants conduct bilateral transactions with other Market Participants, self-commit or self-supply power and energy to the loads they serve.

7.15 Electronic Delivery of Data to FERC

The Market Operator will electronically deliver to FERC, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the FERC, data related to the market that it administers, in accordance with the FERC's regulations.

8. Available Transmission Capacity

8.1 Market Operator Obligation to Constrain the Markets+ Simultaneous Co-optimization Methodology

The Market Operator will create and maintain constraints in the Markets+ Simultaneous Co-optimization Methodology based on the transmission capability available to Markets+.

8.2 Market Operator's Obligation to Coordinate Market Flows and Impacts to Non-Participating Transmission Systems and Balancing Authorities

The Market Operator will coordinate and manage Markets+ market flows and impacts on non-participating transmission systems and Balancing Authorities. This may include, but is not limited to, the creation of Service Flow Constraints to ensure interconnection reliability and to support equitable treatment to the non-participating system(s).

8.3 Obligation to Communicate Transmission Capability

For the appropriate Markets+ timing interval, Markets+ Transmission Service Providers, Markets+ Transmission Contributors, and participating Balancing Authorities will communicate operational transmission capability information to the Market Operator pursuant to the Markets+ Protocols.

9. Settlements

9.2 Day-Ahead Market Settlement

Settlement calculations for Energy and Flexibility Reserve Products in the Day-Ahead Market are based upon the results of the Day-Ahead Market clearing for that Operating Day.

The following Subsections describe the Day-Ahead Market settlement charge types. For each charge type, the calculation is performed at the hourly level for each Market Participant at each Settlement Location. The Market Operator shall calculate hourly summations for each Market Participant for all Asset Owners it represents and shall calculate daily summations as specified in the Markets+ Protocols.

9.2.1 Day-Ahead Energy Amount

A Day-Ahead Market charge or payment for cleared Energy is calculated at each Settlement Location for each Asset Owner for each hour as follows:

(1) For Energy associated with loads and Self-Charging MSRs:

The Day-Ahead Asset Energy Hourly Amount =

(Day-Ahead LMP) * [(Day-Ahead Cleared Load Energy Hourly Quantity) - (Day-Ahead Asset Energy Hourly Markets+ Internal Energy Schedule Settlement Adjustment)]

(a) Day-Ahead LMP associated with that load Settlement Location.

(b) An Asset Owner's Day-Ahead Cleared Load Energy Hourly Quantity is the MW quantity associated with cleared Demand Bids at that load Settlement.

(c) An Asset Owner's Day-Ahead Asset Energy Hourly Markets+ Internal Energy Schedule Settlement Adjustment are those Markets+ Internal Energy Schedule Settlement Adjustment that settle at that load Settlement Location as submitted in accordance with Section 9.1.2 of this Attachment A.

(2) For Energy associated with Resources and MSRs injecting energy into the market:

The Day-Ahead Asset Energy Hourly Amount =

(Day-Ahead LMP) * [(Day-Ahead Cleared Resource Energy Hourly Quantity) - (Day-Ahead Asset Energy Hourly Markets+ Internal Energy Schedule Settlement Adjustment)]

(a) Day-Ahead LMP associated with that Resource Settlement Location.

(b) An Asset Owner's Day-Ahead Cleared Resource Energy Hourly Quantity is the MW quantity associated with cleared Resource Offers at that Resource Settlement Location.

(c) An Asset Owner's Day-Ahead Asset Energy Hourly Markets+ Internal Energy Schedule Settlement Adjustment are those Markets+ Internal Energy Schedule Settlement Adjustment that settle at that Resource Settlement Location as submitted in accordance with Section 9.1.2 of this Attachment A.

(3) For Energy associated with Import Interchange Transactions:

Day-Ahead Non-Asset Energy Hourly Amount =

(Day-Ahead LMP) * [(Day-Ahead Cleared Import Energy Hourly Quantity) – (Day-Ahead Non-Asset Energy Markets+ Internal Energy Schedule Settlement Adjustment)]

(a) Day-Ahead LMP associated with the applicable External Interface Settlement Location.

(b) A Market Participant's Day-Ahead Cleared Import Energy Hourly Quantity is the MW quantity associated with cleared Import Interchange Transaction Offers at that External Interface Settlement Location.

(c) A Market Participant's Day-Ahead Non-Asset Energy Hourly Markets+ Internal Energy Schedule Settlement Adjustment are those Markets+ Internal Energy Schedule Settlement Adjustment that settle at that External Interface Settlement Location.

(4) For Energy associated with Export Interchange Transactions:

Day-Ahead Non-Asset Energy Hourly Amount =

(Day-Ahead LMP) * [(Day-Ahead Cleared Export Energy Hourly Quantity) – (Day-Ahead Non-Asset Energy Markets+ Internal Energy Schedule Settlement Adjustment)]

(a) Day-Ahead LMP associated with the applicable External Interface Settlement Location.

(b) A Market Participant's Day-Ahead Cleared Export Energy Hourly Quantity is the MW quantity associated with cleared Export Interchange Transaction Offers at that External Interface Settlement Location.

(c) A Market Participant's Day-Ahead Non-Asset Energy Hourly Markets+ Internal Energy Schedule Settlement Adjustment are those Markets+ Internal Energy Schedule Settlement Adjustment that settle at that External Interface Settlement Location.

(5) For Energy associated with remaining Markets+ Internal Energy Schedule Settlement Adjustment:

Day-Ahead Non-Asset Energy Hourly Amount =

(Day-Ahead LMP) * [(Day-Ahead Non-Asset Energy Markets+ Internal Energy Schedule Settlement Adjustment) * (-1)]

(a) Day-Ahead LMP associated with the applicable Settlement Location.

(b) An Asset Owner's Day-Ahead Non-Asset Energy Hourly Markets+ Internal Energy Schedule Settlement Adjustment are those Markets+ Internal Energy Schedule Settlement Adjustment that settle at Settlement Locations other than

External Interface Settlement Locations, that Asset Owner's load Settlement Locations or that Asset Owner's Resource Settlement Locations.

(6) For Energy associated with Virtual Energy Bids:

Day-Ahead Virtual Energy Hourly Amount =

(Day-Ahead LMP) * (Day-Ahead Cleared Virtual Energy Bid Hourly Quantity)

(a) Day-Ahead LMP associated with the applicable Settlement Location.

(b) An Asset Owner's Day-Ahead Cleared Virtual Energy Bid Hourly Quantity is the MW quantity associated with cleared Virtual Energy Bids at that Settlement Location.

(7) For Energy associated with Virtual Energy Offers:

Day-Ahead Virtual Energy Hourly Amount =

(Day-Ahead LMP) * (Day-Ahead Cleared Virtual Energy Offer Hourly Quantity)

(a) Day-Ahead LMP associated with the applicable Settlement Location.

(b) An Asset Owner's Day-Ahead Cleared Virtual Energy Offer Hourly Quantity is the MW quantity associated with cleared Virtual Energy Offers at that Settlement Location.

9.2.2 Day-Ahead Virtual Energy Transaction Fee Amount

A Day-Ahead Market charge for each submitted Virtual Energy Offer and Virtual Energy Bid will be calculated for each Market Participant for each Operating Day. Charges collected by the Market Operator under this charge type are used by the Market Operator to reduce the Market Operator budgeted expenses are calculated as follows:

Day-Ahead Virtual Energy Transaction Fee Amount =

[(Day-Ahead Virtual Energy Transaction Daily Count) * (Day-Ahead Virtual Energy Transaction Fee Rate)]

(1) Day-Ahead Virtual Energy Transaction Daily Count is equal to the sum of Virtual Energy Bids and Virtual Energy Offers submitted as of the close of the Day-Ahead Market for all Settlement Locations and hours in the Operating Day.

(2) Day-Ahead Virtual Energy Transaction Fee Rate is $0.05 for each Virtual Energy Offer or Virtual Energy Bid.

9.2.3 Day-Ahead Short-Term Flex Up Amount

A Day-Ahead Market payment for cleared Short-Term Flex Up will be calculated at each Settlement Location for each Asset Owner for each hour as follows:

1. Day-Ahead Short-Term Flex Up Hourly Amount =

   [(Day-Ahead Short-Term Flex Up MCP) * (Day-Ahead Cleared Short-Term Flex Up Hourly Quantity)] * (-1)

   (a) Day-Ahead MCP, as defined under section 3.4, for Short-Term Flex Up associated with the Reserve Zone in which the applicable Resource is located.

   (b) An Asset Owner's Day-Ahead Cleared Short-Term Flex Up Hourly Quantity is the MW quantity associated with cleared Short-Term Flex Up as described under Section 2.1.3 of this Tariff.

9.2.4 Day-Ahead Short-Term Flex Down Amount

A Day-Ahead Market payment for cleared Short-Term Flex Down will be calculated at each Settlement Location for each Asset Owner for each hour as follows:

1. Day-Ahead Short-Term Flex Down Hourly Amount =

   [(Day-Ahead Short-Term Flex Down MCP) * (Day-Ahead Cleared Short-Term Flex Down Hourly Quantity)] * (-1)

   (a) Day-Ahead MCP, as defined under section 3.4, for Short-Term Flex Down associated with the Reserve Zone in which the applicable Resource is located.

   (b) An Asset Owner's Day-Ahead Cleared Short-Term Flex Down Hourly Quantity is the MW quantity associated with cleared Short-Term Flex Down as described under Section 2.1.3 of this Tariff.

9.2.5 Day-Ahead Mid-Term Flex Up Amount

Day-Ahead Mid-Term Flex Up Hourly Amount =

[(Day-Ahead Mid-Term Flex Up MCP) * (Day-Ahead Cleared Mid-Term Flex Up Hourly Quantity)] * (-1)

(a) Day-Ahead MCP, as defined under Section 3.4, for Mid-Term Flex Up associated with the Reserve Zone in which the applicable Resource is located.

(b) An Asset Owner's Day-Ahead Cleared Mid-Term Flex Up Hourly Quantity is the MW quantity associated with cleared Mid-Term Flex Up as described under Section 2.1.3 of this Tariff.

9.2.6 Day-Ahead Short-Term Flex Up Distribution Amount

A Day-Ahead Market charge for Short-Term Flex Up procurement costs calculated under Section 9.2.4 will be calculated at each Reserve Zone for each Asset Owner for each hour as follows:

Day-Ahead Short-Term Flex Up Hourly Distribution Amount =

[(Day-Ahead Short-Term Flex Up Obligation) * (Day-Ahead Short-Term Flex Up Procurement Rate)]

(1) An Asset Owner's Day-Ahead Short-Term Flex Up Obligation in each Reserve Zone is equal to the system wide total of all cleared Short-Term Flex Up multiplied by the Asset Owner Reserve Zone Load Ratio Share, for Short-Term Flex Up being supplied pursuant to Section 4.3.2

(2) For a Reserve Zone that clears more Short-Term Flex Up than the sum of Asset Owners' Day-Ahead Short-Term Flex Up Obligations for that Reserve Zone, the zone is deemed an exporting zone and the Day-Ahead Short-Term Flex Up Procurement Rate is equal to the Short-Term Flex Up MCP for that Reserve Zone.

(3) For a Reserve Zone that clears less Short-Term Flexibility Up Reserve Products than the sum of Asset Owners' Day-Ahead Short-Term Flex Up Obligations for that Reserve Zone, the Day-Ahead Short-Term Flex Up Procurement Rate is as follows:

Day-Ahead Short-Term Flex Up Procurement Rate =

{(Reserve Zone MCP * Total of cleared Short-Term Flex Up for that Reserve Zone) + [(Weighted Average MCP of all Exporting Zones) * (Sum of Asset Owners' Day-Ahead Short-Term Flex Up Obligations for that Reserve Zone - Total of cleared Short-Term Flex Up for that Reserve Zone)]} / (Sum of Asset Owners' Day-Ahead Short-Term Flex Up Obligations for that Reserve Zone).

9.2.7 Day-Ahead Short-Term Flex Down Distribution Amount

A Day-Ahead Market charge for Short-Term Flex Down procurement costs calculated under Section 9.2.5 will be calculated at each Reserve Zone for each Asset Owner for each hour as follows:

Day-Ahead Short-Term Flex Down Hourly Distribution Amount =

[(Day-Ahead Short-Term Flex Down Obligation) * (Day-Ahead Short-Term Flex Down Procurement Rate)]

(1) An Asset Owner's Day-Ahead Short-Term Flex Down Obligation in each Reserve Zone is equal to the system wide total of all cleared Short-Term Flex Down multiplied by the Asset Owner Reserve Zone Load Ratio Share for Short-Term Flex Down being supplied pursuant to Section 7.5.

(2) For a Reserve Zone that clears more Short-Term Flex Down than the sum of Asset Owners' Day-Ahead Short-Term Flex Down Obligations for that Reserve Zone, the zone is deemed an exporting zone (shall it be importing instead) and the Day-Ahead Short-Term Flex Down Procurement Rate is equal to the Short-Term Flex Down MCP for that Reserve Zone.

(3) For a Reserve Zone that clears less Short-Term Flex Down than the sum of Asset Owners' Day-Ahead Short-Term Flex Down Obligations for that Reserve Zone, the Day-Ahead Short-Term Flex Down Procurement Rate is as follows:

Day-Ahead Short-Term Flex Down Procurement Rate =

{(Reserve Zone MCP * Total of cleared Short-Term Flex Down for that Reserve Zone) + [(Weighted Average MCP of all Exporting Zones) * (Sum of Asset Owners' Day-Ahead Short-Term Flex Down Obligations for that Reserve Zone - Total of cleared Short-Term Flex Down for that Reserve Zone)]} / (Sum of Asset Owners' Day-Ahead Flex Down Obligations for that Reserve Zone).

9.2.8 Day-Ahead Mid-Term Flex Up Distribution Amount

A Day-Ahead Market charge for Mid-Term Flex Up Reserve procurement costs calculated under Section 9.2.6 will be calculated at each Reserve Zone for each Asset Owner for each hour as follows:

Day-Ahead Mid-Term Flex Up Hourly Distribution Amount =

[(Day-Ahead Mid-Term Flex Up Products Obligation) * (Day-Ahead Mid-Term Flex Up Procurement Rate)]

(1) An Asset Owner's Day-Ahead Mid-Term Flex Up Obligation in each Reserve Zone is equal to the system wide total of all cleared Mid-Term Flex Up multiplied by the Asset Owner Reserve Zone Load Ratio Share for Mid-Term Flex Up being supplied pursuant to Section 7.5 of this Tariff.

(2) For a Reserve Zone that clears more Mid-Term Flex Up than the sum of Asset Owners' Day-Ahead Mid-Term Flex Up Obligations for that Reserve Zone, the zone is deemed an exporting zone and the Day-Ahead Mid-Term Flex Up Procurement Rate is equal to the Mid-Term Flex Up MCP for that Reserve Zone.

(3) For a Reserve Zone that clears less Mid-Term Flex Up than the sum of Asset Owners' Day-Ahead Mid-Term Flex Up Obligations for that Reserve Zone, the Day-Ahead Mid-Term Flex Up Procurement Rate is as follows:

Day-Ahead Mid-Term Flex Up Procurement Rate =

{(Reserve Zone MCP * Total of cleared Mid-Term Flex Up for that Reserve Zone) + [(Weighted Average MCP of all Exporting Zones) * (Sum of Asset Owners' Day-Ahead Mid-Term Flex Up Obligations for that Reserve Zone - Total of cleared Mid-Term Flex Up for that Reserve Zone)]} / (Sum of Asset Owners' Day-Ahead Mid-Term Flex Up Obligations for that Reserve Zone).

9.2.9 Day-Ahead Make Whole Payment Amount

(1) The Day-Ahead make whole payment amount is a payment to an Asset Owner and is calculated for each Resource with an associated Day-Ahead Market Commitment Period that was committed as defined in Sections 4.1(7)(a) and 4.1(7)(c) of this Attachment A. If the Market Monitor determines Resources committed in an RMR status were selected in a discriminatory manner by the Transmission Operator, Participating Balancing Authority, or Reliability Coordinator, as described under Section 2.3.1.4.1 of this Attachment A, then such Resources are not eligible to receive a Day-Ahead Market make whole payment. A payment is made to a Market Participant when a Resource's costs are greater than the Day-Ahead Market revenues received during the Resource's Day-Ahead Market make whole payment eligibility period. The make whole payment is equal to this difference between those costs and revenues.

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

(3) The following cost recovery rules apply to each Day-Ahead Market make whole payment eligibility period. Offer costs are calculated using the Day-Ahead Market Offer prices in effect at the time the commitment decision was made.

(a) There may be more than one Day-Ahead Market make whole payment eligibility period for a Resource in a single Operating Day for which a charge or payment is calculated. A single Day-Ahead Market make whole payment eligibility period is contained within a single Operating Day.

(b) A Resource's Day-Ahead Market commitment level offer costs include Start-Up Offer, Transition State Offer, and RUC remainder for a Day-Ahead Market make whole payment eligibility period in which that Resource is committed with a Day-Ahead Market Resource Offer commitment status. The commitment level cost

eligible for recovery is calculated by subtracting all Start-Up Offer cost and Transition State Offer cost associated with a Day-Ahead Market Resource Offer commitment status from all eligible commitment level Offer costs required to execute the Day-Ahead schedule associated with the Day-Ahead Market make whole payment eligibility period. The resulting difference represents either a charge or a payment and is a cost component when determining a Day-Ahead Market make whole payment.

(i) In any Day-Ahead Market make whole payment eligibility period for which the Day-Ahead Market Simultaneous Co-optimization Methodology did not consider the Resource's Start-Up Offer in the original commitment decision, the Resource's Start-Up Offer shall equal zero unless the Resource's Start-Up Offers costs are associated with RMR commitments.

(ii) A Resource's Day-Ahead Market Start-Up Offer cost is not eligible for recovery in the following Day-Ahead Market make whole payment eligibility periods:

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

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

(1) The cost allocated to the RUC make whole payment will not be greater than the difference between: (a) the Day-Ahead Market

Start-Up Offer and Transition State Offer costs at the adjacency point of the RUC and Day-Ahead Market commitment; and (b) Day-Ahead Market Start-Up Offer and Transition State Offer costs associated with a Day-Ahead Market Resource Offer commitment status at the adjacency point.

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

(iv) A Resource's Day-Ahead Market Transition State Offer costs for a Day-Ahead Market commitment are eligible for recovery in the Day-Ahead Market make whole payment eligibility period except when the Day-Ahead Market Simultaneous Co-optimization Methodology did not consider the Resource's Transition State Offer in the Day-Ahead commitment decision unless Transition State Offers costs are associated with RMR commitments.

(v) As described under Section 9.3.12(3)(g) of this Attachment A, to the extent that the full amount of the eligible RTBM Start-Up cost is not accounted for in the adjacent RUC make whole payment eligibility period, any remaining RTBM Start-Up cost is carried forward for recovery in the adjacent Day-Ahead make whole payment eligibility period.

(vi) When a Resource loses eligibility to recover a Day-Ahead Market Start-Up Offer cost for the reason described in Section 9.2.10(3)(b)(ii)(1) of this Attachment A, to prevent overstating avoided costs, the commitment level cost is adjusted by the lesser of: (a) the Resource's Start-Up Offer cost and Transition State Offer cost associated with a Day-Ahead Market Resource Offer commitment statuses defined under Sections 4.1(7)(a) and 4.1(7)(c) of this Attachment A; or (b) the ineligible Day-Ahead Market Start-Up Offer cost.

(vii) For each Day-Ahead Market make whole payment eligibility period within an Operating Day, a Resource's eligible Start-Up cost is divided by the lesser of (1) the Resource's applicable Minimum Run Time rounded down to the nearest hour or (2) twenty-four (24) hours, to achieve an hourly

proration for the purpose of allocating Start-Up costs across adjacent Day-Ahead commitments.

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

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

(c) For an MCR, additional costs or revenues are incurred when the Resource has cleared Flexibility Reserve Products in the Day-Ahead Market and must buy back that position in real-time at an average hourly real-time MCP. These costs or revenues will be considered as an adjustment when determining a Day-Ahead Market make whole payment. These costs or revenues must be incurred during a time period in the Day-Ahead Market make whole payment eligibility period in which the Resource is transitioning in real-time due to a Day-Ahead scheduled transition that is not forced by the Resource Offer.

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

(e) If a Resource is committed by the Market Operator in the Day-Ahead Market, the Resource will be eligible to recover applicable recurring costs for that period in the Day-Ahead Market make whole payment eligibility period.

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

Day-Ahead Make Whole Payment Amount =

Maximum of [Either Zero or Sum of ((Day-Ahead Make Whole Payment Cost Amount in the Day-Ahead Market Make Whole Payment Eligibility Period) + (Day-Ahead Make Whole Payment Revenue Amount in the Day-Ahead Market Make Whole Payment Eligibility Period) + (Day-Ahead Make Whole Payment Commitment Cost))] * (-1)

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

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

(ii) Energy cost associated with cleared Resource Energy, including MSRs providing a market service, from Resource Energy Offers, as calculated by multiplying cleared Resource Energy by the cost of such Energy as calculated from the Resource's Day-Ahead Market Energy Offer Curve,

(b) A Market Participant's Day-Ahead Make Whole Payment Revenue Amount for each eligible Resource that is committed by the Market Operator is equal to the sum for all hours in the Day-Ahead Market Make Whole Payment Eligibility Period of:

(i) Energy revenue associated with cleared Resource Energy, and MSRs providing a market service, from Resource Energy Offers, calculated by multiplying Resource Energy by Day-Ahead LMP at that Resource Settlement Location, and

(ii) The sum of the revenues calculated under Section 9.2.4, 9.2.5 and 9.2.6 of this Attachment A for that eligible Resource.

(c) Market Participant's Day-Ahead Make Whole Payment Commitment Cost Amount for each eligible Resource in the Day-Ahead Market Make Whole Payment Eligibility Periods is equal to:

(i) Day-Ahead Market Start-Up Offer or any RUC remainder amount as described in Section 9.2.10(3)(b) of this Attachment A, plus

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

(iii) Any amount of Start-Up costs where the Resource loses eligibility to recover as described in Section 9.2.10(3)(b)(v) of this Attachment A, minus

(iv) Any amount of shared Start-Up costs between Day-Ahead Market and RUC make whole payment eligibility periods as described in Section 9.2.10(3)(b)(ii) of this Attachment A, minus

(v) All Start-Up and Transition State Offer costs associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(7)(a) and 4.1(7)(c) of this Attachment A.

9.2.10 Day-Ahead Make Whole Payment Distribution Amount

A Day-Ahead Market Balancing Authority Area charge will be calculated at each Settlement Location for each Market Participant for each hour in order to fund the payments made under Section 9.2.9 of this Attachment A. The Balancing Authority Area amount will be determined by multiplying a Market Participant's Balancing Authority Area distribution volume by a daily Balancing Authority Area Day-Ahead Market make whole payment rate as described in this Section 9.2.10.

The Day-Ahead Balancing Authority Area Make Whole Payment Distribution Amount shall be calculated as follows:

Day-Ahead Balancing Authority Area Make Whole Payment Distribution Amount =

(Day-Ahead Balancing Authority Area Make Whole Payment Distribution Rate) * (Day-Ahead Balancing Authority Area Make Whole Payment Distribution Quantity))

(1) The Day-Ahead Balancing Authority Area Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day per Balancing Authority Area divided by the sum of all Market Participants' Day-Ahead Balancing Authority Area Make Whole Payment Distribution Quantities for all Settlement Locations in the Balancing Authority Area for the entire Operating Day.

(2) A Market Participant's Day-Ahead Balancing Authority Area Make Whole Payment Distribution Quantity at a Settlement Location for an hour is equal to that Market Participant's cleared Energy withdrawals at that Settlement Location for that hour. A Market Participant's Energy withdrawal at a Settlement Location is calculated as the sum of cleared Demand Bids, cleared Self-Charging MSR Offers, Export Interchange Transaction Bids and Virtual Energy Bids at that Settlement Location.

9.2.11 Day-Ahead Demand Reduction Amount

A Day-Ahead Market payment will be calculated for each Asset Owner with registered load Settlement Locations containing one or more Demand Response Loads associated with cleared Demand Response Resource Offers for each applicable Settlement Location and each hour as follows:

Day-Ahead Demand Reduction Hourly Amount =

(Day-Ahead LMP) * (Day-Ahead Total Demand Response Resource Hourly Quantity)

(1) Day-Ahead LMP, as defined under Section 3.2 of this Attachment A, for a load Settlement Location containing one or more Demand Response Loads associated with cleared Demand Response Resource Offers.

(2) An Asset Owner's Day-Ahead Total Demand Response Resource Hourly Quantity is the sum of the MW quantities for cleared Demand Response Resources in the Day-Ahead Market, as described under Section 2.1.3 of this Attachment A, that are associated with the load Settlement Location referenced in (1) above.

9.2.12 Day-Ahead Demand Reduction Distribution Amount

Within each Balancing Authority Area, the Day-Ahead Demand Reduction Distribution Amount is an hourly charge to Asset Owners at each Settlement Location to recover the sum of the demand reduction payments made under Section 9.2.11 of this Attachment A and is calculated as:

Day-Ahead Demand Reduction Distribution Amount =
(Day-Ahead Demand Reduction Distribution Rate) * (Day-Ahead Demand Reduction Distribution Quantity))

(1) The Day-Ahead Demand Reduction Distribution Rate is the sum of all demand reduction payments, within the applicable Balancing Authority Area, for the hour multiplied by (-1), divided by the sum of all Asset Owners' Day-Ahead Demand Reduction Distribution Quantities for all Settlement Locations, within the Balancing Authority Area, for the hour.

(2) A Market Participant's Day-Ahead Balancing Authority Area Demand Reduction Distribution Quantity at a Settlement Location for an hour is equal to that Market Participant's cleared Energy withdrawals at that Settlement Location for that hour. A Market Participant's Energy withdrawal at a Settlement Location is calculated as the sum of cleared Demand Bids, cleared Self-Charging MSR Offers, Export Interchange Transaction Bids and Virtual Energy Bids at that Settlement Location.

9.3 Real-Time Balancing Market Settlements

Settlement calculations for the RTBM are performed on a Dispatch Interval basis for each Operating Day and are based upon the difference between the results of the RTBM and the Day-Ahead Market clearing for that Operating Day. To calculate RTBM actual Energy in a Dispatch Interval for Market Participants that have not directly submitted five (5) minute interval Meter Data, the Market Operator allocates the submitted hourly Meter Data for Resources and loads into five (5) minute values using five (5) minute telemetered or State Estimator profiles for the corresponding hour. The profiling of the hourly Meter Data maintains the shape of the five (5) minute telemetered or State Estimator values even if there are both positive and negative values contained within the twelve (12) intervals.

The following subsections describe the RTBM settlement charge types. For each charge type, the calculation is performed either at the Dispatch Interval level or hourly level for each Asset Owner at each Settlement Location. The Market Operator shall calculate hourly summations for each Market Participant for all Asset Owners it represents and shall calculate daily summations.

9.3.1 Real-Time Energy Amount

An RTBM payment or charge for Energy is calculated at each Settlement Location for each Asset Owner for each Dispatch Interval and hour as follows:

(1) For Energy associated with loads, and Self-Charging MSRs:

(a) Real-Time Asset Energy Dispatch Interval Amount =

Real-Time LMP * [((Real-Time Load Billing Meter Quantity) – (Day-Ahead Cleared Load Energy Quantity)) – (Real-Time Asset Energy Markets+ Internal Energy Schedule Settlement Adjustments)] / 12

(i) Real-Time LMP associated with that load, Self-Charging MSR, or station power from offline generation Settlement Location.

(ii) A Market Participant's Real-Time Load Billing Meter Quantity at that Settlement Location is the aggregation of (i) the five (5) minute Meter Data Submittal Location values submitted by the Meter Agent to the Market Operator, multiplied by twelve (12) or the aggregation of (ii) the hourly Meter Data Submittal Location values profiled into five (5) minute

increments by the Market Operator if the Market Participant elects to submit hourly Meter Data. The Market Operator shall make any necessary adjustments to the submitted Meter Data Submittal Location values.

(iii) A Market Participant's Day-Ahead Cleared Load Energy Quantity is the MW quantity associated with cleared Demand Bids and cleared Self-Charging MSR Offers at that Settlement Location.

(iv) A Market Participant's Real-Time Asset Energy Markets+ Internal Energy Schedule Settlement Adjustments are those Markets+ Internal Energy Schedule Settlement Adjustments that settle at that load Settlement Location as submitted in accordance with Section 9.1.2 of this Attachment A.

(b) Real-Time Asset Energy Hourly Amount =

Sum of Real-Time Asset Energy Dispatch Interval Amount over all Dispatch Intervals in the Hour.

(2) For Energy associated with Resources:

(a) Real-Time Energy Dispatch Interval Amount =

Real-Time LMP * [((Real-Time Resource Billing Meter Quantity) – (Day-Ahead Cleared Resource Energy Hourly Quantity)) – (Real-Time Asset Energy Markets+ Internal Energy Schedule Settlement Adjustments)] / 12

(i) Real-Time LMP associated with that Resource Settlement Location.

(ii) An Asset Owner's Real-Time Resource Billing Meter Quantity at that Resource Settlement Location, excluding Self-Charging MSRs is (i) the five (5) minute actual meter MWh Resource output quantity submitted by the Meter Agent to the Market Operator, multiplied by twelve (12) or (ii) the hourly actual meter MWh Resource injection or withdrawal quantity profiled into five (5) minute increments by the Market Operator using the method described under Section 9.3 of this Attachment A if the Asset Owner elects to submit hourly Meter Data.

(iii) An Asset Owner's Day-Ahead Cleared Resource Energy Hourly Quantity is the MW quantity associated with cleared Resource Offers excluding Self-

Charging MSRs at that Resource Settlement Location as described under Section 2.1.3 of this Attachment A.

(iv) An Asset Owner's Real-Time Asset Energy Markets+ Internal Energy Schedule Settlement Adjustments are those Markets+ Internal Energy Schedule Settlement Adjustments that settle at that Resource Settlement Location as submitted in accordance with Section 9.1.2 of this Attachment A.

(b) Real-Time Energy Hourly Amount =

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

(3) For Energy associated with Interchange Transactions:

(a) Real-Time Non-Asset Energy Dispatch Interval Amount =

Real-Time LMP * ((Real-Time Import Energy Quantity) – (Day-Ahead Import Energy Quantity)) / 12

(i) Real-Time LMP associated with the applicable External Interface Settlement Location.

(ii) A Market Participant's Real-Time Import Energy Quantity is the five (5) minute Dispatch Interval MW quantity scheduled for use in the RTBM, adjusted for curtailments, at that External Interface Settlement Location.

(iii) A Market Participant's Day-Ahead Import Energy Quantity is the five (5) minute Dispatch Interval MW quantity calculated by the Market Operator for each Dispatch Interval by multiplying the scheduled MW in the Dispatch Interval by the ratio of (a) hourly scheduled amount for use in the Day-Ahead Market and (b) the MW amount of cleared Import Interchange Transaction Offers as described under Section 2.1.3 of this Attachment A, at that External Interface Settlement Location.

(4) For Energy associated with Export Interchange Transactions:

(a) Real-Time Non-Asset Energy Dispatch Interval Amount =

Real-Time LMP * ((Real-Time Export Energy Quantity) – (Day-Ahead Export Energy Quantity)) / 12

(i) Real-Time LMP associated with the applicable External Interface Settlement Location.

(ii) A Market Participant's Real-Time Export Energy Quantity is the five (5) minute Dispatch Interval MW quantity scheduled for use in the RTBM, adjusted for curtailments, at that External Interface Settlement Location.

(iii) A Market Participant's Day-Ahead Export Energy Quantity is the five (5) minute Dispatch Interval MW quantity calculated by the Market Operator for each Dispatch Interval by multiplying the scheduled MW in the Dispatch Interval by the ratio of (a) hourly scheduled amount for use in the Day-Ahead Market and (b) the MW amount of cleared Export Interchange Transaction Bids, as described under Section 2.1.3 of this Attachment A, at that External Interface Settlement Location.

(b) Real-Time Non-Asset Energy Hourly Amount =

Sum of Real-Time Non-Asset Energy Dispatch Interval Amount over all Dispatch Intervals in the Hour.

(5) For Energy associated with remaining Markets+ Internal Energy Schedule Settlement Amount:

Real-Time Non-Asset Energy Hourly Amount =

(Real-Ahead LMP) * [(Real-Time Non-Asset Energy Markets+ Internal Energy Schedule Settlement Amount for Energy) * (-1)]

(a) Real-Time LMP, as defined under Section 1 of this Attachment A, associated with the applicable Settlement Location.

(b) An Asset Owner's Real-Time Non-Asset Energy Hourly Markets+ Internal Energy Schedule Settlement Amount for Energy are those Markets+ Internal Energy Schedule Settlement Amount that settle at Settlement Locations other than External Interface Settlement Locations, that Asset Owner's load Settlement Locations or that Asset Owner's Resource Settlement Locations, as submitted in accordance with Section 9.1.2 of this Attachment A.

(6) For Energy associated with Day-Ahead Market cleared Virtual Energy Bids:

Real-Time Virtual Energy Dispatch Interval Amount =

[(Real-Time LMP) * ((Day-Ahead Cleared Virtual Energy Bid Hourly Quantity) / 12)] * (-1)

(a) Real-Time LMP associated with the applicable Settlement Location.

(b) A Market Participant's Day-Ahead Cleared Virtual Energy Bid Hourly Quantity is the MW quantity associated with cleared Virtual Energy Bids as described under Section 2.1.3 of this Attachment A at that Settlement Location.

(7) For Energy associated with Day-Ahead Market cleared Virtual Energy Offers:

Real-Time Virtual Energy Dispatch Interval Amount =

[(Real-Time LMP) * ((Day-Ahead Cleared Virtual Energy Offer Hourly Quantity) / 12)] * (-1)

(a) Real-Time LMP associated with the applicable Settlement Location.

(b) A Market Participant's Day-Ahead Cleared Virtual Energy Offer Hourly Quantity is the MW quantity associated with cleared Virtual Energy Offers as described under Section 2.1.3 of this Attachment A at that Settlement Location.

9.3.16 Reliability Unit Commitment Make Whole Payment Amount

(1) For each Markets+ Balancing Authority Area, Asset Owners of Resources committed by the Market Operator during the RUC processes as defined in Sections 4.1(7)(a) and 4.1(7)(c) of this Attachment A, are eligible to receive a RUC make whole payment. If the Market Monitor determines Resources committed in an RMR status were selected in a discriminatory manner by the Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator, as described under Section 2.3.1.4.1 of this Attachment A, then such Resources are not eligible to receive a Day-Ahead Market make whole payment. A RUC make whole payment is made to the Asset Owner when the sum of a Resource's costs associated with actual Energy and cleared RTBM Flexibility Reserve is greater than the RTBM revenues received over the Resource's RUC make whole payment eligibility period. Recovery of such compensation shall be collected in accordance with Section 9.3.17 of this Attachment A.

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

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

(b) For an MCR that cleared in the Day-Ahead Market and was transitioned to a different configuration in real-time by the Market Operator, the costs in the intervals preceding the RUC commitment for the purpose of buying back Flexibility Reserve Products while the Resource transitions to the RUC committed

configuration, as defined by the Transition State Time submitted in the Resource Offer, are included in the RUC make whole payment calculation.

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

(a) If a Market Commitment is canceled by a Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator prior to the start of the associated RUC make whole payment eligibility period, the Asset Owner will receive reimbursement for a time-based pro-rata share of the Resource's RTBM Start-Up Offer unless precluded by Section 9.3.12(3)(e)(i) of this Attachment A.

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

(c) In order to receive recovery of No-Load Offer costs in any Dispatch Interval in the RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in that Dispatch Interval.

(d) There may be more than one RUC make whole payment eligibility period for a Resource in a single Operating Day. A single RUC make whole payment eligibility period is contained within a single Operating Day.

(e) A Resource's RUC commitment level offer costs include Start-Up Offer cost and Transition State Offer cost for a RUC make whole payment eligibility period in which that Resource is committed with a RTBM Resource Offer commitment status as defined under Section 4.1(7)(a) or (c) of this Attachment A. The commitment level cost eligible for recovery is calculated by subtracting: (1) all Start-Up Offer cost and Transition State Offer cost associated with the schedule created by combining all Day-Ahead Market commitments with a Day-Ahead Market Resource Offer commitment status as defined under Section 4.1(7)(a) or (c) of this Attachment A contained within a RUC make whole payment eligibility period and all RUC commitments that are associated with a RTBM Resource Offer

commitment status as defined under Section 4.1(7)(a) or (c) of this Attachment A within a RUC make whole payment eligibility period; from (2) all eligible commitment level offer costs associated with the final Resource schedule in a RUC make whole payment eligibility period. The resulting difference can represent a charge or a payment and is considered as an adjustment when determining a RUC make whole payment.

(i) Except for an MCR that is committed by RUC in a different configuration than in the Day-Ahead Market, when a RUC make whole payment eligibility period is created after a Day-Ahead make whole payment eligibility period and is adjacent and preceding that Day-Ahead make whole payment eligibility period where the Day-Ahead Start-Up Offer Amount defined in Section 9.2.10(3)(b)(i) of this Attachment A was considered, the Day-Ahead Start-up Offer Amount is used in place of the RUC Start-up costs.

(ii) In any RUC make whole payment eligibility period for which the Simultaneous Co-optimization Methodology did not consider the Resource's Start-Up Offer in the original commitment decision, except for commitments made as described under Sections 2.2.2(3) of this Attachment A, the Resource's Start-Up Offer shall equal zero.

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

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

(iv) When there is a cost transferred from the Day-Ahead Market make whole payment as described in Section 9.2.10(3)(b)(iii) of this Attachment A, the

commitment level cost in the RUC make whole payment is increased by the amount allocated to the RUC make whole payment as described in Section 9.2.10(3)(b)(iii) of this Attachment A.

(v) In any RUC make whole payment eligibility period for which the Simultaneous Co-optimization Methodology considered the Resource's Transition State Offer in the original commitment decision, or the RTBM Transition State Offer is associated with a manual commitment as described under Sections 2.2.2(3) of this Attachment A, the Transition State Offer cost is eligible for recovery when the following conditions are met:

(1) In at least one Dispatch Interval during the scheduled configuration period, the Resource is in the target "from" configuration and the Resource must be a Synchronized Resource; and

(2) In at least one Dispatch Interval during the scheduled configuration period, the Resource is in the target "to" configuration and the Resource must be a Synchronized Resource.

(vi) If a transition is canceled by a Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator between configurations prior to the scheduled transition associated with a RUC make whole payment eligibility period, the Asset Owner will be eligible to recover a time-based pro-rata share of the Resource's RTBM Transition State Offer through the RUC make whole payment unless precluded by Section 9.3.12(3)(e)(i) of this Attachment A.

(vii) When a Resource loses eligibility to recover a Start-Up Offer cost for the reason described in Section 9.3.12(3)(e)(iii)(1) of this Attachment A, or loses eligibility to recover Transition State Offer costs for the reason described in Section 9.3.12(3)(v) of this Attachment A, to prevent overstating avoided costs, the commitment level cost is adjusted by the lesser of: (1) its Start-Up Offer cost and Transition State Offer cost associated with commitments that have a RTBM Resource Offer commitment status as defined under Section 4.1(7)(a) or (c) of this

Attachment A; or (2) the ineligible RTBM Start-Up Offer cost plus the ineligible Transition State Offer costs.

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

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

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

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

(g) If a Resource has operated outside of its Operating Tolerance in any Dispatch Interval, any cost associated with energy injection or withdrawal above the

Resource's economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated.

(h) If a Resource becomes non-dispatchable in any Dispatch Interval, any cost associated with energy injection or withdrawal above the Resource's economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated.

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

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

(k) If a Resource is committed by the Market Operator, Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator in the RTBM, the Resource will be eligible to recover applicable recurring costs for that period in the RUC make whole payment eligibility period.

(l) For an MCR, additional costs of revenues incurred when the Resource has cleared Flexibility Reserve Products in the Day-Ahead Market and must buy back that position in real-time will be considered as an adjustment when determining a RUC make whole payment. These costs or revenues must be incurred during time periods in which the Resource is ineligible to clear Flexibility Reserve Products due to transitioning between configurations in real-time where at least one configuration is the result of a RUC commitment, and the transition is not forced by the Resource Offer. The Market Participant may also be eligible to recover Flexibility Reserve Product buy back costs incurred during a Real-Time transition if the Resource is transitioned by a Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator. The Market Participant is not eligible to recover Flexibility Reserve Product buy back costs if the Market Monitor determines such Resources were selected in a discriminatory manner by the Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator, as determined pursuant to Section 2.3.1.4.1 of Attachment A to the Tariff, and such Resources were affiliated with the Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator. In such cases, the adjustment is equal to the sum of the cleared Day-Ahead Market Flexibility Reserve Products revenue as calculated from the Day-Ahead Flexibility Reserve Products MCP and the cleared incremental RTBM Flexibility Reserve Products revenue as calculated from the RTBM Flexibility Reserve Products MCPs. For Flexibility Reserve Products the adjustment is limited to the time period defined as the Transition State Time submitted in the Resource Offer.

(4) The payment to each Asset Owner for each eligible Settlement Location in the applicable Markets+ Balancing Authority Area, for a given RUC make whole payment eligibility period is calculated as follows:

RUC Make Whole Payment Amount =

Maximum of [Either Zero or (RUC Make Whole Payment Commitment Cost Amount + RUC Make Whole Payment Cost Amount in the RUC Make Whole Payment Eligibility Period + RUC Make Whole Payment Revenue Amount in the RUC Make Whole Payment Eligibility Period – Uninstructed Resource Deviation Cost Disallowance – Non-

Dispatchable Cost Disallowance – Minimum Limit Cost Disallowance + Real-Time Combined Cycle Flexibility Reserve Products Adjustment Amounts)]

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

(i) Start-Up Offer used to make the commitment decision which was committed by the Market Operator, Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator; plus

(ii) The Transition State Offer used to make the transition decision for an MCR that cleared in the Day-Ahead Market or committed by the RUC process that was transitioned by Market Operator, Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator into a different configuration in real-time plus

(iii) Real-Time Cancelled Transition Amount; plus

(iv) Amount of shared Start-Up costs between Day-Ahead Market and RUC make whole payment eligibility periods; plus

(v) Amount of costs where the Resource loses eligibility to recover, minus

(vi) The sum of all Start-Up Offer cost and Transition State Offer cost associated with the schedule created by combining (1) all Day-Ahead Market commitments with a Day-Ahead Market Resource Offer commitment status contained within a RUC make whole payment eligibility period and (2) all RUC commitments that are associated with a RTBM Resource Offer commitment status within a RUC make whole payment eligibility period.

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

(i) No-Load Offer used to make the RUC commitment decision, less any Day-Ahead Market No-Load from an MCR resulting from a different Day-Ahead Market committed configuration;

(ii) Energy cost at minimum injection or withdrawal as calculated from the Energy Offer Curve used to make the commitment decision;

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

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

(vi) For an MCR that was cleared in the Day-Ahead Market and was committed into a different configuration in real-time and is not transitioning into that configuration, the Flexibility Reserve Products cost associated with cleared real-time Flexibility Reserve Products minus Day-Ahead Flexibility Reserve Products cost associated with the lesser of (1) cleared real-time Flexibility Reserve Products or (2) cleared Day-Ahead Flexibility Reserve Products;

(c) An Asset Owner's RUC Make Whole Payment Revenue Amount for each eligible Resource that is committed by the Market Operator, Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator is equal to the sum of the following for all Dispatch Intervals in the RUC commitment:

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

(ii) Energy revenue associated with payments made under section 9.3.18 of the Attachment A;

(iii) Real-Time Base Obligation Short-Term Flex Up Amount as calculated under section 9.3.2 of this Attachment A.

(iv) Real-Time Increased Obligation Short-Term Flex Up Amount as calculated under section 9.3.3 of this Attachment A.

(v) Real-Time Short-Term Flex Down Amount as calculated under section 9.3.4 of this Attachment A.

(vi) Real-Time Base Obligation Mid-Term Flex Up Amount as calculated under section 9.3.5 of this Attachment A.

(vii) Real-Time Increased Obligation Mid-Term Flex Up Amount as calculated under section 9.3.6 of this Attachment A.

(d) An Asset Owner's Uninstructed Resource Deviation Cost Disallowance, Non-Dispatchable Cost Disallowance, or Minimum Limit Cost Disallowance is equal to the positive difference between the Resource's Energy cost at actual injection or withdrawal as calculated from the Resource's current Dispatch Interval Energy Offer Curve and the Resource's Energy cost at the Resource's economic operating point as calculated from the Resource's current Dispatch Interval Energy Offer Curve.

(e) A Resource's economic operating point is the MW injection or withdrawal where the cost on the Resource's current Dispatch Interval Energy Offer Curve first exceeds the real-time DLMP for that Resource.

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

9.3.17 Reliability Unit Commitment Make Whole Payment Distribution Amount

An RTBM Balancing Authority Area charge will be calculated at each Settlement Location for each Asset Owner for each hour in order to fund the payments made under Sections 9.2.13, 9.3.29 and 9.3.20 of this Attachment A. The Balancing Authority Area amount will be determined by multiplying an Asset Owner's Balancing Authority Area distribution volume by a daily Balancing Authority Area RUC make whole payment rate as described in Section 9.3.14(A) of this Attachment A.

A. The RUC Balancing Authority Area Make Whole Payment Distribution Amount shall be calculated as follows:

The RUC Balancing Authority Area Make Whole Payment Distribution Amount =
[(RUC Balancing Authority Area Make Whole Payment Distribution Rate) *
(RUC Balancing Authority Area Make Whole Payment Distribution MW quantity)]

(1) The RUC Balancing Authority Area Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day as calculated under Section 9.2.13 divided by the sum of Asset Owners' RUC Balancing Authority Area Make Whole Payment Distribution MW quantity for all Settlement Locations for the entire Operating Day.

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

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

(b) For Resources cleared in the Day-Ahead Market, except MCRs with an RTBM Resource Offer commitment status as defined under Section

4.1(7)(a) or (c) of this Attachment A, that have been transitioned in real-time by the Market Operator, Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator into a real-time configuration with a higher applicable minimum capacity operating limit than the Day-Ahead Market committed configuration, the positive difference between the RTBM Resource applicable minimum limits and Day-Ahead Market Resource cleared Energy quantity provided that:

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

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

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

(c) For Resources cleared in the Day-Ahead Market, except combined cycle Resources with an RTBM Resource Offer commitment status as defined under Section 4.1(7)(a) or (c) of this Attachment A that have been transitioned in real-time by the Market Operator, Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator into a Real-Time configuration with a lower applicable maximum capacity operating limit than the Day-Ahead Market committed configuration, the positive difference between the Resource Day-Ahead Market cleared Energy quantity and the RTBM Resource applicable maximum limit provided that:

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

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

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

(d) For Resources cleared in the Day-Ahead Market, the Resource's Day-Ahead Market cleared amount if that Resource is off-line in the RTBM and if the Resource has not been de-committed by a Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator or dispatched to zero by the Market Operator;

(e) For Resources that cleared in the Day-Ahead Market that are not able to follow Dispatch Targets, including an MCR that is not in its committed configuration, the absolute value of the difference between a Resource's actual injection or withdrawal and the Resource's economic operating point. The Resource's economic operating point is calculated as described under Section 9.3.13(4)(e) of this Attachment A;

(f) For Resources that self-committed following the close of the Day-Ahead Market, the actual Resource injection or withdrawal if the Resource received a Dispatch Target with an absolute value less than or equal to the RTBM applicable minimum charge or discharge limit for at least one Dispatch Interval in the hour;

(g) A Resource's economic operating point, as calculated as described under Section 9.3.13(4)(e) of this Attachment A, for Resource or MCR configuration that was committed following the close of the Day-Ahead Market if that Resource is off-line in the RTBM and that Resource was not de-committed by the Markets+ Transmission Service Provider, Balancing Authority, or Reliability Coordinator including, for an MCR, the amount of the incremental MWs from Day-Ahead Market cleared Energy to real-time economic operating point; and

(h) The absolute value of a Resource's URD if that Resource operated outside of its Operating Tolerance and the Resource has not been exempted from URD as described under Section 9.4.1 of this Attachment A.

9.6 Market Transmission Use Amount

The Market Operator will perform the following calculation for each Operating Day for each Markets+ Transmission Service Provider.

Market Transmission Use (MTU) Amount = Daily MTU Distribution Amount * MTU Ratio Share * (-1)

(1) The Daily MTU Distribution Amount is the value calculated in Section 9.9 of this Attachment A.

(2) The MTU Ratio Share is equal to the Markets+ Transmission Service Provider Revenue Recovery Amount (MTSPRRA) divided by the approved Region-Wide Revenue Recovery Amount (RWRRA). MTSPRRA and RWRRA are as defined in Appendix 2 of this Attachment A.

9.7 Market Transmission Use Distribution Amount

A charge or credit will be calculated for each Asset Owner at each Settlement Location for the Operating Day for the purposes of funding payments made under Section 9.8 of this Attachment A as follows:

Daily MTU Distribution Amount =
Region-Wide Market Transmission Use Rate * Sum of Asset Owners' Daily Market Activity across all Settlement Locations

(1) The Region-Wide Market Transmission Use Rate is equal to the amount calculated per the MTU formula template in Appendix 2 of Attachment A of this Tariff and is equal to twice the sum of all Markets+ Transmission Service Provider Revenue Recovery Amounts (MTSPRRA) divided by twice the sum of all Markets+ Transmission Service Provider Net Energy for Load (MTSPNEL). MTSPRRA and MTSPNEL are as defined in Appendix 2 of this Attachment A.

(2) The sum of the Asset Owner's Market Activity at a Settlement Location for an Operating Day is equal to the sum of:
   (a) The absolute value of actual metered generation for the Operating Day;
   (b) The absolute value of actual metered load for the Operating Day; and
   (c) The absolute value of scheduled Interchange Transactions for the Operating Day; and
   (d) The absolute value of cleared Virtual Energy Offers and Bids for the Operating Day.

The SPP-Wide Market Activity is equal to the sum of all Asset Owners' Market Activity for the Operating Day.

11.0 Confidentiality Provisions

This Section 11 shall apply to Confidential Information disclosed by a Market Participant to the Market Operator or by the Market Operator to the Market Monitor, FERC, the CFTC, or an Authorized Requestor.

11.1 Restrictions on Confidential Information Provided to Receiving Party

A party in receipt of Confidential Information ("Receiving Party") may not disclose Confidential Information received from a party disclosing said Confidential Information ("Disclosing Party") to any person, corporation, or any other entity except as specifically permitted in this Section 10 of this Attachment A.

11.1.1 Procedures for Confidential Information

Receiving Party shall adopt procedures within its organization to maintain the confidentiality of all Confidential Information. Such procedures must provide that:

(1) The Confidential Information will be disclosed to Receiving Party's directors, officers, employees, representatives and agents only on a "need to know" basis;

(2) Receiving Party shall make its directors, officers, employees, representatives and agents aware of Receiving Party's obligations under this Section 10;

(3) Receiving Party shall cause any copies of the Confidential Information that it creates or maintains, whether in hard copy, electronic format, or other form, to identify the Confidential Information as such, and to retain confidential markings; and

(4) Before disclosing Confidential Information to a contractor or vendor of Receiving Party, Receiving Party shall require a non-disclosure agreement with each such contractor or vendor. Such nondisclosure agreement shall contain confidentiality provisions substantially similar to the terms of this Section 10.

11.1.2 Exceptions

Without violating the confidentiality provisions of this Section 10, a Receiving Party may disclose certain Confidential Information:

(1) As required by any law, regulation, or order, or as expressly required or permitted by this Tariff, provided that the Receiving Party must make reasonable efforts to restrict public access to the disclosed Confidential Information by protective order, by aggregating information, or otherwise if reasonably possible; or

(2) If the Disclosing Party that supplied the Confidential Information to the Receiving Party has given its prior written consent to the disclosure as set forth in Subsection 10.1.4(3), which consent may be given or withheld in Disclosing Party's sole discretion; or

(3) If, before it is furnished to Receiving Party, the Confidential Information is in the public domain; or

(4) If, after it is furnished to Receiving Party, the Confidential Information enters the public domain other than through a manner inconsistent with the provisions of this section; or

(5) If reasonably deemed by the Receiving Party to be required to be disclosed in connection with a dispute between Receiving Party and Disclosing Party; provided that the Receiving Party must make reasonable efforts to restrict public access to the disclosed Confidential Information by protective order, by aggregating information, or otherwise if reasonably possible; or

(6) To a vendor or prospective vendor of Market Operator so long as such vendor or prospective vendor: (i) is not a Market Participant; (ii) has a need to know in connection with its business with the Market Operator; and (iii) executes a confidentiality agreement with terms substantially similar to those in this Section 10.

11.1.3 Injunctive Relief and Specific Performance

It may be impossible or very difficult to measure in terms of money the damages that would accrue due to any breach by Receiving Party of this section, or any failure to perform any obligation contained in this section, and, for that reason, among others, a Disclosing Party affected by such a disclosure or threatened disclosure may be entitled to injunctive relief, including specific performance of this section (but is not hereby precluded from seeking other forms of relief). In the event that a Disclosing Party institutes any proceeding to enforce any part of this section, the affected Receiving Party, by entering any agreement incorporating this Tariff, agrees that it will not assert any claim or defense that an adequate remedy at law or other remedy would be adequate for such a breach.

11.1.4 Market Participant Access and Market Operator Use of Confidential Information

(1) No Market Participant shall have a right hereunder to receive or review any documents, data, or other information of another Market Participant, including documents, data, or other information provided to the Market Operator, to the extent such documents, data, or information is Confidential Information under this section; provided, however, a Market Participant may receive and review any composite documents, data, and other information that may be developed based on such Confidential Information if the composite does not, directly or by its nature, disclose any individual Market Participant's Confidential Information.

(2) The Market Operator shall collect and use Confidential Information only in connection with its authority under this Tariff and the retention of such information shall be in accordance with the Market Operator's retention policies. Except as otherwise provided in Sections 10.1.2, 10.1.5, 10.2 and 10.3, the Market Operator shall not disclose to a Market Participant or to any third party, any Confidential Information of a Market Participant or a Market Participant applicant; provided that nothing contained herein shall prohibit the Market Operator from providing a Market Participant's Confidential Information to requesting entities to the extent that: (i) the Market Operator determines, in its reasonable discretion, that the exchange of such information is required for reliability within the Markets+ Footprint; (ii) such receiving entity is bound by a written agreement to maintain such confidentiality; and (iii) the Market Operator has notified the affected Market Participant of its intention to release such information no less than five (5) Business Days prior to the release.

(3) Nothing contained herein shall prevent the Market Operator from releasing a Market Participant's Confidential Information to a third party provided that the Market Participant has delivered to the Market Operator specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Operator shall limit the release of a Market Participant's Confidential Information to that specific authorization received from the Market Participant. Nothing herein shall prohibit a Market Participant from

withdrawing such authorization upon written notice to the Market Operator who shall cease such release as soon as practicable after receipt of such withdrawal notice.

11.1.5 Required Disclosure

(1) If a Receiving Party is required by applicable law, or in the course of administrative or judicial proceedings, other than Commission, CFTC, or state regulatory proceedings or investigations, to disclose to third parties, other than to the Commission, the CFTC, or their staffs, Confidential Information that is otherwise required to be maintained in confidence pursuant to this Tariff, the Receiving Party subject to such disclosure requirement may disclose such information; provided, however, that the Receiving Party shall not release the data until the affected Disclosing Party(ies) provide written consent or until the affected Disclosing Party's(ies') legal avenues to prevent the disclosure are exhausted, except as provided in Sections 10.2, 10.3 and 10.4. As soon as the Receiving Party learns of the disclosure requirement and prior to making disclosure, it shall notify the affected Disclosing Party(ies) of the requirement and the terms thereof and the date on which it may be required to disclose the information. The affected Disclosing Party(ies) may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Receiving Party shall cooperate with such affected Disclosing Party(ies) to the maximum extent practicable to minimize the disclosure of the Confidential Information consistent with applicable law. To the extent reasonably possible, the Receiving Party will maintain the confidentiality of Confidential Information subject to this Section 10.1.5 with (a) a protective order, (b) other procedures available for protecting confidential data or (c) by aggregating data to prevent disclosure of Confidential Information. Each Receiving Party shall cooperate with the affected Disclosing Party's(ies') effort or pursuit to obtain proprietary or confidential treatment of such Confidential Information by the person to whom such information is disclosed prior to any such disclosure.

(2) Section 10.1.5(1) does not apply to disclosure of information to the Commission or its staff, the CFTC or its staff, or to a state regulator or its staff.

11.1.6 Limitations

Nothing contained in Section 10.1 through and including Section 10.1.5 shall require any Receiving Party to violate any law or file a lawsuit in order to prevent disclosure of Confidential Information.

11.2 Confidentiality Provisions Applicable to the Market Monitor

(1) The Market Operator is authorized to provide Confidential Information to the Market Monitor. For purposes of Confidential Information provided by the Market Operator to the Market Monitor, the Market Operator will be considered to be a Disclosing Party, and for purposes of this Section 10.2, the Market Monitor will treat both the Market Operator and, if known to the Market Monitor, the Market Participant originally providing specific Confidential Information as Disclosing Parties in the event the Market Monitor receives a request for Confidential Information under this Section 10.2.

(2) The Market Monitor shall use all reasonable procedures necessary to protect and preserve the confidentiality of all Confidential Information it receives.

(3) The Market Monitor shall not disclose Confidential Information to any person or entity except to the Commission or its staff or the CFTC or its staff, without prior written consent. However, the Market Monitor may disclose its referrals to FERC's Office of Enforcement to a market monitoring unit of an ISO or RTO without written consent if (i) the substance of the referral relates to or may reasonably be expected to involve interregional behavior affecting the ISO or RTO, (ii) reasonable precautions are taken to ensure that all referral information remains non-public and (iii) such disclosure is otherwise permitted by and in accordance with applicable FERC orders.

(4) Upon receipt of a subpoena or other compulsory process from a source other than the Commission or its staff or the CFTC or its staff for the disclosure of Confidential Information, the Market Monitor shall promptly notify the affected Disclosing Party(ies) that originally provided the data and shall provide all reasonable assistance requested by the affected Disclosing Party(ies) to prevent disclosure, and if possible under the terms of the subpoena or other compulsory process shall not release the data until the affected Disclosing Party(ies) provide written consent or until the affected Disclosing Party(ies') legal avenues to prevent disclosure are exhausted. To the extent reasonably possible, the confidentiality of Confidential Information subject to Section 10.2(2) will be maintained with (i) a

protective order, (ii) other procedures available for protecting confidential data, or (iii) by aggregating data to prevent disclosure of Confidential Information.

11.3 Disclosure to Commission or CFTC

(1) If the Commission or CFTC or their respective staffs requests Confidential Information from the Market Operator and/or the Market Monitor that is otherwise required to be maintained in confidence pursuant to this Tariff, the Market Operator and/or the Market Monitor, as applicable shall provide the requested information to the Commission, CFTC, or their respective staffs within the time provided for in the request for information. Should the Market Operator and/or the Market Monitor require additional time to provide the information requested due to logistical matters such as the volume of information requested or technical complexity involved, the Market Operator and/or the Market Monitor will promptly communicate that need to the entity requesting the information and shall establish the time for production of the requested information.

(2) In providing the information to the Commission or its staff, the Market Operator and the Market Monitor shall, consistent with 18 C.F.R. §§ 1b.20 and/or 388.112, request that the Confidential Information be treated as confidential and non-public by the Commission and its staff and that the Confidential Information be withheld from public disclosure. The Market Operator and/or the Market Monitor shall promptly notify the affected Disclosing Party(ies) that originally submitted the requested Confidential Information when it receives from the Commission or its staff a request for disclosure of Confidential Information.

(3) In providing the information to the CFTC or its staff, the Market Operator and the Market Monitor shall, consistent with 17 C.F.R §§ 11.3 and 145.9, request that the Confidential Information be treated as confidential and non-public by the CFTC and its staff and that the Confidential Information be withheld from public disclosure. If the Market Operator and/or the Market Monitor receives notice from the CFTC or its staff that Confidential Information provided by the Market Operator and/or the Market Monitor is to be released, it shall promptly notify the affected Disclosing Party(ies) in order to afford the affected Disclosing Party(ies) an opportunity to respond before such information would be made public.

11.4 Disclosure to Authorized Agencies

11.4.1 Basic Requirements for Disclosure

The Market Operator or Market Monitor shall only disclose Confidential Information to an Authorized Requestor under the following conditions:

(1) The Authorized Requestor has executed the non-disclosure agreement in Attachment F with the Market Operator; and

(2) The Market Operator is able to verify that the Authorized Agency employing or retaining the Authorized Requestor has provided the Market Operator with the following information pursuant to Section 2.2 of Attachment F to this Tariff:

(a) A list of authority (including statutory) specifying the particular Authorized Agency's duty, responsibility, or authority in fulfillment of which it will make requests to the Market Operator or the Market Monitor under this section for information, including, but not limited to, that enumerated and described as available to the Market Monitor in Attachment C of this Tariff; or, in the case of a regional state committee, a FERC order prohibiting the release of Confidential Information by the regional state committee, except in accordance with the terms of the non-disclosure agreement;

(b) A statement notifying and identifying to the Market Operator that the Authorized Agency has practices or procedures in place adequate to protect against the unauthorized release of Confidential Information; and

(c) Confirmation in writing that the Authorized Requestor is authorized by the Authorized Agency to enter into the non-disclosure agreement and to receive Confidential Information under Attachment A of this Tariff.

11.4.2 Use of Confidential Information

The Authorized Requestor shall use the Confidential Information for the purpose of assisting an Authorized Agency in discharging its duty, responsibility or authority in fulfillment of which it authorizes Authorized Requestors to make requests for Confidential Information and for no other purpose. Any and all Authorized Requestors authorized by the same Authorized Agency may have access to the Confidential Information that is provided to that Authorized Agency.

11.4.3 Limited Oral Disclosures

The Market Operator or the Market Monitor may, in the course of discussions with an Authorized Requestor or Authorized Requestors in meetings or teleconferences, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. The Market Operator or the Market Monitor will not make any written or electronic disclosures of Confidential Information to the Authorized Requestor pursuant to this section. The Market Operator or Market Monitor shall also be authorized to assist Authorized Requestors in interpreting Confidential Information that is disclosed.

11.4.4 Information Requests

(1) Form: Information Requests to the Market Operator or the Market Monitor shall be in writing and shall include electronic communications addressed to the Market Operator or to the Market Monitor as appropriate.

(2) Content: Each Information Request shall describe, in as much detail as possible, the particular information sought, including the time period for the requested information; provide a description of the purpose for which the information is being sought, and state the time period for which it is expected that the information will need to be retained by the Authorized Requestor.

(3) Notice: The Market Operator or the Market Monitor shall provide an affected Market Participant with notice of and a copy of an Information Request by an Authorized Requestor as soon as practicable.

(4) Disclosure: Subject to the provisions of Section 10.4.4(6) and (7) below, the Market Operator or the Market Monitor shall supply the information sought to the Authorized Requestor in response to any Information Request within ten (10) Business Days after the receipt of the Information Request, or within such longer period as may be specified by the Information Request, unless a timely objection has been made to the Information Request, or unless the requested information can only reasonably be made available within an extended time period.

To the extent that the Market Operator or the Market Monitor cannot reasonably prepare and deliver the requested information within a ten (10) Business Day period or any longer period specified in the Information Request, it shall, within such period, hold discussions with the Authorized Requestor and provide the Authorized Requestor with a mutually agreed upon written schedule for the provision of such remaining information. Upon providing the requested information to the Authorized Requestor, the Market Operator or the Market Monitor may provide a copy of the disclosed information to the affected Market Participant(s), or provide a listing of the Confidential Information disclosed; provided, however, that the Market Operator or the Market Monitor shall not reveal

any affected Market Participant's Confidential Information to any other Market Participant.

(5) Objection and Clarification: Notwithstanding Section 10.4.4(4) above, should the Market Operator, the Market Monitor or an affected Market Participant object to an Information Request or any portion thereof to the Authorized Agency, any of them or the Authorized Agency may, within ten (10) Business Days following the Market Operator's or the Market Monitor's receipt of the Information Request, request, in writing, a conference with the Authorized Agency, or the Authorized Requestor, to resolve differences concerning the scope or time period covered by the Information Request; provided, however, nothing herein shall require the Authorized Agency to participate in any conference.

Any party to the conference may seek assistance from FERC staff in resolution of the dispute or initiate legal action at FERC. Any complaints filed at FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint.

If no FERC proceeding regarding the Information Request is commenced within five (5) Business Days following notice from any participant refusing or terminating such conference, the Market Operator or the Market Monitor may respond to the Information Request within five (5) Business Days or any longer period that may be specified by the Information Request, counted from the expiration of such five-day period.

(6) Opportunity to Respond to Confidentiality Claims: If the affected Market Participant, the Market Operator or the Market Monitor considers the information sought by the Information Request as Confidential Information, the Authorized Requestor shall be provided an opportunity to challenge, through the dispute resolution process set forth in Section 6, the designation or classification of the requested information as Confidential Information.

(7) Response to Tailored Request for Information from State Commissions: Market Monitor may respond to tailored requests for information from state commissions regarding general market trends and the performance of the wholesale market, but

not for information designed to aid state enforcement actions. Granting or refusing such requests will be at the Market Monitor's discretion.

(8) Limitation On Disclosure Obligation: The Market Operator or the Market Monitor shall not be required to make disclosure in response to an Information Request:

(a) In circumstances where an electronic data link, dedicated communication circuit or other hardware or third party services would be necessary to effectuate the disclosure;

(b) That is of a scope or extent materially similar to the flow of data from Market Participants to the Market Operator or from the Market Operator to the Market Monitor;

(c) That is unduly burdensome; or

(d) That is not pertaining to general market trends or the performance of the Market Operator.

11.4.5 Breach of Non-Disclosure Obligations

In the event of any breach of a non-disclosure agreement entered into in connection with this Section 10.4:

(1) The Authorized Requestors and/or their respective Authorized Agency shall promptly notify the Market Operator or the Market Monitor, who shall, in turn, promptly notify any affected Market Participant of any unauthorized release of Confidential Information provided pursuant to any non-disclosure agreement.

Upon notification, the Market Operator will cease disclosure to the Authorized Requestor pursuant to any Information Request and will make no disclosure pursuant to any Information Request pending from the Authorized Requestor until it can be determined after consultation with the Authorized Requestor, the corresponding Authorized Agency and the affected Market Participant that an appropriate combination of the following factors justifies resumption of the Authorized Requestor's access to Confidential Information: (i) the unauthorized disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Requestor; (ii) there was no harm or economic damage suffered by the affected Market Participant; (iii) there are now practices or procedures in place adequate to prevent a recurrence of the unauthorized disclosure; and/or (iv) similar good cause shown.

(2) If the Market Operator or the Market Monitor receives from an Authorized Requestor or Authorized Agency a written notice that a breach has occurred, or FERC has made a ruling that a breach has occurred, the Market Operator and/or the Market Monitor may terminate the non-disclosure agreement and require either the immediate return of all Confidential Information obtained by the Authorized Requestor pursuant to the non-disclosure agreement or a certification of its destruction.

The Market Operator shall verify the breach in consultation with the Authorized Agency. If it is subsequently determined that there was no breach, or if otherwise justified by circumstances described in Subsection (2) above, the Market Operator shall restore the status of the Authorized Requestor. Any other rights and remedies shall be pursuant to the terms of the non-disclosure agreement.

(3) No Authorized Requestor, who is an employee of an Authorized Agency, shall have responsibility or liability whatsoever under the non-disclosure agreement or Attachment A to this Tariff for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of Confidential Information to persons not authorized to receive it.

However, nothing in this Section 10.4.7(3) is intended to limit the liability of any person who is not an employee of or a member of an Authorized Agency, to the degree not granted limitations as to liability under applicable state law of the Authorized Agency's state, when such a person is under contract to perform services for the Authorized Agency, for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

11.5 Preservation of Rights

A Disclosing Party shall have the right to pursue all appropriate actions to prevent or contest any attempt to remove the confidential status or any order removing such confidential status of its Confidential Information.

Any Receiving Party seeking to dispute the designation of information as Confidential Information may challenge such designation through the dispute resolution process as established in Section 6 of this Tariff.

Appendix 1 to Attachment A
Violation Relaxation Limit Values

This Appendix 1 to Attachment A sets forth the VRL values to be used in SCOM.

Constraint Type	Description	VRL [$/MW]
(1) Resource Capacity	The minimum and maximum MW dispatchable output of a resource as indicated in a Resource Offer.	100,000
(2) Global Power Balance	Energy needed to balance resources and load.	50,000
(3) Resource Ramp	The ramp capability of a resource as indicated in the resource plan.	5,000
(4a) Operating Constraint not subject to Market-to-Market coordination	A MW limit that can be imposed on SPP related to MW flow across a market node, a manually-identified transmission constraint, a Watch List transmission constraint, a flowgate constraint, or a transmission constraint identified by SPP's real-time contingency analysis.	$750/*$1,750 when the loading is greater than 100% and less than or equal to 101% at each network constraint at each Operating Constraint.
		$1,000/*$2,000 when the loading is greater than 101% and less than or equal to 102% at each network constraint
		$1,250/*$2,250 when the loading is greater than 102% and less than or equal to 103% at each network constraint
		$1,500/*$2,500 when the loading is greater than 103% and less than or equal to 104% at each network constraint
		$1,750/*$2,750 when the loading is greater than 104% at each network constraint

* Applies only when MMU has authorized one or more Resource Offers in excess of $1,000.

Appendix 2 to Attachment A
Market Transmission Use Rate Template

A. Calculation of Region-Wide Market Transmission Use Revenue Recovery Amount

In calculating the Market Transmission Use Region-Wide Revenue Recovery Amount, the Market Operator will sum the applicable Markets+ Transmission Service Provider's Revenue Recovery Amounts (MTSPRRA) submitted for input to this Formula Rate Template. Each Markets+ Transmission Service Provider's (MTSP's) portion of such Region-Wide Recovery Amount (RWRRA) shall be adjusted according to Section 7.11(F).

B. Calculation of Region-Wide Market Transmission Use Net Energy For Load

In calculating the Market Transmission Use Region-Wide Net Energy for Load (RWNEL), the Market Operator shall sum the applicable Markets+ Transmission Service Provider's Net Energy for Load (MTSPNEL) submitted for input to this Formula Rate Template.

C. Billing Determinants

Definitions: These definitions are to be used in this Appendix 2 only; in the event of a conflict between these definitions and other definitions in the Tariff, these definitions control in the interpretation of this Appendix 2; other capitalized terms are defined elsewhere in this Tariff.

1. Markets+ Transmission Service Provider Qualified Revenue Amount (MTSPQRA) – The amount of Short-Term Firm (STF) and Non-Firm (NF) Point-to-Point (PTP) revenues for an MTSP as an average of the last three (3) year period prior to the MTSP joining Markets+.

2. Region-Wide Net Energy for Load (RWNEL) – Aggregation of Markets+ Transmission Service Provider's Net Energy for Load (MTSPNEL) for each Markets+ Transmission Service Provider included in the MTU rate basis for the Markets+ footprint. Billing Determinant is used in the Region-Wide Market Transmission Use Rate (RWMTURt) denominator.

3. Region-Wide Market Transmission Use Rate (RWMTURt) – Markets + Footprint-wide rate for Market Transmission Use per megawatt hours of market activity as defined in Section iii.

4. Region-Wide Revenue Recovery Amount (RWRRA) - Aggregated total of all participating Markets+ Transmission Service Provider's Revenue Recovery Amount (MTSPRRA) in the Markets+ footprint used in rate basis for MTU recovery; it is also the denominator for MTU revenue distribution pro-rata determination for each participating MTSP.

5. Markets+ Transmission Service Provider's Net Energy for Load (MTSPNEL) – Individual MTSP's net generation of generating units that are system-owned or system-operated, plus energy receipts minus energy deliveries.

6. Markets+ Transmission Service Provider's Revenue Recovery Amount (MTSPRRA) - Total estimated recovery amount per MTSP for MTU recovery; this is the MTU revenue distribution numerator for each MTSP.

7. Markets+ Transmission Service Provider Annual Transmission Revenue Requirement (MTSPATRR) – MTSP's current year effective Annual Transmission Revenue Requirement (ATRR) amount.

8. Markets+ Transmission Service Provider Annual Transmission Revenue Requirement Average (MTSPATRRAVG) – MTSP's prior three year average of Annual Transmission Revenue Requirements (ATRR) prior to the MTSP joining Markets+.

9. Markets+ Transmission Service Provider Prior-Year Market Transmission Use Offset (MTSPPYMO) – Individual MTSP's calculated prior year MTU over / under recovery of MTU revenue in relation to that year's MTSPRRA for the same MTSP.

10. Markets+ Transmission Service Provider Carryover Market Transmission Use Offset (MTSPPYMCO) – Individual MTSP's carryover under/over recovery amount unable to be realized into the following year's MTSPRRA due to reducing the MTSPRRA to zero.

11. Markets+ Transmission Service Provider Recovery Scaling Factor (MTSPRSF) - The estimated percentage, limited between 0 – 100%, of Market+ Transmission Service Provider Qualified Revenue Amount (MTSPQRA) that would be affected by Markets+ participation;

12. Markets+ Transmission Service Provider Qualified Revenue Ratio (MTSPQRR) - Individual MTSP's Transmission Service Provider Qualified Recovery Amount (MTSPQRA) divided by its MTSP Annual Transmission Revenue Requirement (ATRR) as an average of the last three (3) year period prior to MTSP joining Markets+.

13. Markets+ Transmission Service Provider Short-Term Firm Point-To-Point Revenue (MTSPSTFRev) – MTSP's revenue amount from Short-Term Firm (STF) Point-to-Point (PTP) Transmission Service sales.

14. Markets+ Transmission Service Provider Non-Firm Point-To-Point Revenue (MTSPNFRev) – MTSP's revenue amount from Non-Firm (NF) Point-to-Point (PTP) Transmission Service sales.

15. Expected Markets+ Transmission Service Provider Qualified Revenue Amount (EMTSPQRA) - MTSP current year ATRR multiplied by the Markets+ Transmission Service Provider Qualified Recovery Ratio (MTSPQRR); Intermediate step in determining annual update for Markets+ Transmission Service Provider Recovery Scaling Factor (MTSPRSF) representing an MTSP's

expected level of Short-Term Firm (STF) and Non-Firm (NF) Point-to-Point (PTP) revenues based on its currently effective ATRR.

D. Formula

where RWMTURt = RWRRA/RWNEL

RWRRA = SUM MTSPRRA
RWNEL = ((SUM MTSPNEL) X 2)

where MTSPRRA = (((MTSPATRR * MTSPQRR) * MTSPRSF)+ MTSPPYMO+MTSPP
MTSPQRR = TPQRA / TPATRRAVG
MTSPQRA = 3YR AVG MTSPTFRev & TPNFRev
MTSPATRRAVG = 3YR AVG TPATRR

I. ***Markets+ Transmission Service Provider Qualified Recovery Amount (MTSPQRA)***

Line No.		**MTSP1**
1	Year 1 Prior to Markets+ Short-Term Firm Revenue	-
2	Year 2 Prior to Markets+ Short-Term Firm Revenue	-
3	Year 3 Prior to Markets+ Short-Term Firm Revenue	-
4	3 Year Average ln1 : ln3	-
5	Year 1 Prior to Markets+ Non-Firm Revenue	-
6	Year 2 Prior to Markets+ Non-Firm Revenue	-
7	Year 3 Prior to Markets+ Non-Firm Revenue	-
8	3 Year Average ln5 : ln7	-
9	**TPQRA:** ln4 + ln8	-

II. *Markets+ Transmission Service Provider ATSTR (1) Average (TSPATRRAVG)*

Line No.		**MTSP1**
1	Year 1 Prior to Markets+ ATRR	-
2	Year 2 Prior to Markets+ ATRR	-
3	Year 3 Prior to Markets+ ATRR	-
4	**TSPATRRAVG**: 3 Year Average ln1 : ln3	-

III. *Markets+ Transmission Service Provider Qualified Revenue Ratio (MTSPQRR)*

Line No.		**MTSP1**
1	Markets+ Transmission Service Provider Qualified Recovery Amount , Section I; ln9 Above	-
2	Markets+ Transmission Service Provider ATTR Average, Section II; ln4 Above	-
3	**TPQRR:** ln1 / ln2	**0.000%**

IV. *Markets+ Transmission Service Provider Revenue Recovery Amount (MTSPRRA)*

Line No.		**MTSP1**
1	**MTSPATRR**[1] : Markets+ Transmission Service Provider Annual Revenue Requirement	-
2	Markets+ Transmission Service Provider Qualified Revenue Ratio **(MTSPQRR)**, Section III; ln3 above	0.000%
3	**Expected MTSPQRA**: ln1 x ln2	-
4	Markets+ Transmission Service Provider Revenue Scaling Factor **(MTSPRSF);** Worksheet C, ln5	0%
5	**Unadjusted MTSPRRA**: ln3 x ln4	-
6	**MTSPPYMO:** Markets+ Transmission Service Provider Prior Year (Over)/Under Recovery; Worksheet B, ln3	-
7	Greater of ln4 + ln5, or 0	-
8	**MTSPPYMCO:** Markets+ Transmission Service Provider Carry Over (Over)/Under Recovery, Worksheet B, ln7	-

9	**MTSPRRA:** Greater of ln7 + ln8, or 0	-

1- Current Year ATRR

V. *Markets+ Transmission Service Provider Net Energy Load (MTSPNEL)*

Line No.		**MTSP1**
1	Current Year Net Energy Load	-
2	**MTSPNEL**: ln1 x 2	-

VI. Region Wide Markets+ Transmission Service Provider Net Energy Load (MTSPNEL)

Line No.		
1	**RWNEL**: Sum Section V; ln2 above for all MTSPs	-

VII. Region Wide Markets+ Transmission Service Provider Revenue Recovery Amount (RWMRRA)

Line No.		
1	**RWRRA:** Sum Section IV; ln9 above for all MTSPs	-

VIII. Region Wide Market Transmission Use Rate (RWMTURt)

Line No.		
1	**RWMTURt**: Section VII;ln1 Above / Section VI; ln1 above	-

B - (Over) / Under Recovery Carryover Worksheet

Line No.		MTSP1
1	Prior Year TPRRA (0 if Year 1)	-
2	Prior Year Actual MTU Revenue (0 if Year 1)	-
3	**MTPPYMO:** Markets+ Transmission Service Provider Prior Year (Over)/Under Recovery (ln 1 - ln2)	-
4	**Unadjusted TPRRA** Part A; Section IV; ln5 Above	-
5	Unused Prior Year (Over)/Under Recovery: Lesser of 0 or ln3 + ln4	-
6	Part A; Section IV; ln7 Above	-
7	**MTSPPYMCO:** Markets+ Transmission Service Provider Carry Over (Over)/Under Recovery (Prior Year FRT - Part B, ln9)	-
8	Unused Carryover (Over)/Under Recovery: Lesser of 0 or ln6 + ln7	-
9	**Total (Over)/Under Recovery Carryover Amount**	**-**

C - Revenue Scaling Factor

Line No.		MTSP1
1	**Expected MTSPQRA;** Section IV; ln3 above	$ -
2	Prior Year ST F/NF Revenue, If Year 1 = 0	$ -
3	ST F/NF Revenue loss or (gain) (ln1 – ln2)	$ -
4	STF/NF loss or (gain) as a % of Expected TPQRA (ln 3/ ln 1)	0%
5	**Current Year RSF: If ln 4 > 0,RSF = ln4 , if ln4 <= 0, RSF=0, if Year 1 RSF = 50%**	**0%**

ANNUAL FORMULA RATE IMPLEMENTATION PROTOCOLS

Section 1 **Applicability**

The formula rate template and these Annual Formula Rate Implementation Protocols (collectively, the "Formula Rate") comprise the Markets+ Region-Wide

MTU rates. The Market Operator shall follow the Formula Rate to calculate annually its Region-Wide MTU rate. The Formula Rate and the charges produced thereunder shall be effective on and after MONTH, DAY, YEAR implementation of the Markets+ Tariff. Thereafter, the Formula Rate shall be applicable on and after each calendar year (the "Rate Year") after Markets+ implementation, subject to the true-up procedures of this Appendix 2.

Section 2 **Annual Updates**

a. Within fifteen (15) calendar days after the conclusion of the Rate Year period, the MTSP shall submit most recent audited data for input into the Formula Rate template for calculation of the next Rate Year's MTU Rate.

i. Billing Determinants needed in the calculation of each MTSP's portion of the overall rate, as defined in this Appendix 2, shall be sent to Market Operator via secure, electronic format and contain all data necessary to complete the template;

ii. supporting documentation from MTSP, including, but not limited to, fully functioning Excel files (or such other native format files), required to support, demonstrate and explain information upon which the Annual Update is based shall accompany the Billing Determinants listed above;

b. Within ten (10) business days after the Market Operator receives applicable data for updates from the MTSP, the Market Operator, shall determine and post, the annual update to be effective during the next Rate Year, which shall consist of the following ("Annual Update"):

i. a data-populated version of the Formula Rate template setting forth the MTU Rate for the next Rate Year, as defined in this Appendix 2, produced by operation of the Formula Rate;

ii. supporting documentation from MTSPs, including, but not limited to, fully functioning Excel files (or such other native format files), required to support, demonstrate and explain information upon which the Annual Update is based;

iii. disclosure of the following changes to the extent any has taken effect since Markets+ Tariff implementation, and materially affects the Formula Rate or calculation of the Annual Update or the allocation of costs or revenues to the MTU Rates:

(a) any Federal Energy Regulatory Commission ("FERC" or "Commission") ratemaking orders applicable to the Market Transmission Use Rate; and

(b) the accounting practices or procedures of the Market Operator and/or the MTSP.

Changes in items (a) and (b) collectively referred to as "*Material Changes*".

c. The Market Operator shall post the Annual Update on the Market Operator's website and notify interested parties via the Market Operator's email exploder titled "Market Transmission Use Formula Rate Posting Information Notification". The posting shall include fully functioning Excel files (or such other native format file) of all materials contained in the Annual Update.

d. The Annual Update for the new Rate Year shall:

i. be based upon the MTSP's most recent Billing Determinants as defined in this Appendix 2, and other information for the new Rate Year, that reasonably reflect amounts comprising the MTU Rate, consistent with the MTSP's practices or procedures, and the Market Operator's Tariff; and

ii. compute the MTU Rate

e. In the posting of the Annual Update, the Market Operator shall request written comments be provided for the period of two (2) weeks after the posting of the Annual Update.

f. The Market Operator shall file the revised Annual Update with the Commission once the MTU Rate is calculated and posted as described in this Appendix 2.

Section 3 Intra-Rate Year Updates

In instances where a new Markets+ Transmission Service Provider joins the Markets+ footprint during a current MTU Rate Year, the current MTU Rate will be updated to reflect that

Markets+ Transmission Service Provider's Billing Determinants at the time of that Markets+ Transmission Service Provider's joining Markets+, provided:

1) The Markets+ Transmission Service Provider submits all required Annual Update information listed in Section 2 (i) and (ii) above, as well as any other required information, at least ninety (90) days prior to their joining Markets+,
2) The Market Operator is able to compile all necessary data, recalculate the active MTU rate with these additions, and adhere to any other applicable requirements listed in the Appendix 2 prior to the new Markets+ Transmission Service Provider joining Markets+, and
3) The subsequent Formula Rate changes are approved by the Commission.

Such Intra-Rate Year updates will become effective at the beginning of the Operating Month the Markets+ Transmission Service Provider joins Markets+, provided conditions 1 and 2 above were met in such time that allows the Commission's approval to be granted prior to that date; otherwise, they will become effective at the beginning of the first full Operating Month after Commission's approval.

After joining Markets+ and having its Billing Determinants update the Formula Rate Intra-Rate Year, the Markets+ Transmission Service Provider must adhere to Annual Update terms and conditions as normal.

Section 4 Changes to Formula Rate Initiated by the Markets+ Transmission Service Provider or Market Operator

Any changes to the Formula Rate initiated by the MTSPs or the Market Operator, including any changes necessitated by Material Changes, may only be implemented as a result of a filing and approval by the Commission.

Addendum 1 to Attachment A
Resource Adequacy and the Western Resource Adequacy Program ("WRAP")

Prior to participation in Markets+, a Load Responsible Entity with load registered in Markets+ shall submit to the Market Operator an attestation signed by an authorized officer in the form attached as "Appendix A." The Market Operator may terminate the Load Responsible Entity's registration in Markets+ if: (i) the Load Responsible Entity fails to submit the attestation; or (ii) the Market Operator deems the attestation insufficient.

Appendix A

This Attestation is made for and on behalf of_____ (the "Load Responsible Entity"), and submitted to the Market Operator as a requirement for registration in Markets+.

I, [Name], the [Title] of the Load Responsible Entity, in my capacity as an [officer/authorized delegate] of the Load Responsible Entity, and not in my personal capacity, hereby attest that:

a) I have authority to make these statements on behalf of the Load Responsible Entity;
b) The Load Responsible Entity is a Participant (as defined in the WRAP Tariff) in WRAP;
c) As of the date of this Attestation, to the best of my knowledge after due inquiry, the Load Responsible Entity satisfies all applicable requirements of the WRAP Tariff, including the Forward Showing Program as defined and set forth in the WRAP Tariff, as amended and approved by FERC; and
d) The Load Responsible Entity acknowledges that it must notify the Market Operator if, at any time, the Load Responsible Entity ceases to be a Participant and, if the Load Responsible Entity ceases to be a Participant, the Market Operator may terminate the Load Responsible Entity's registration in Markets+, all in accordance with the Markets+ Tariff.

IN WITNESS WHEREOF, the undersigned has executed this certificate as of [Date].

Signature: _____

Name: _____

Title: _____

ATTACHMENT D
Markets+ Transmission

The Market Operator will provide two services in support of Markets+ Transmission Capability:

1) Support transmission scheduling adjustments for market usage, as described in this Attachment D.
2) Optimize the use of the transmission system pursuant to this Attachment D.

1.0 General

By the close of the Day-Ahead Market, Markets+ Transmission Service Providers and Markets+ Transmission Contributors will communicate pursuant to the Markets+ Protocols, operational transmission capability information to the Market Operator for deriving a market solution utilizing a Simultaneous Co-optimization Methodology pursuant to Attachment A, Section 8.3.

Once the Markets+ day-ahead clearing process is complete, the Market Operator system will send tag market adjustment(s) to the participating BAs to adjust the BA-to-BA Markets+ tags. The Market Operator will also communicate the cleared market volume amount via a market adjustment to reflect price-sensitive imports or exports to be approved by the tagging entities.

Participating Balancing Authorities shall communicate to the Market Operator any changes to the transmission capability communicated to the Market Operator before such change becomes effective in the next Dispatch Interval.

Markets+ will economically dispatch Energy across the Markets+ Footprint using Markets+ Transmission Contributors' and Markets+ Transmission Service Providers' flow-based transmission capability less any capacity not available for market use. The energy produced within a Resource's Operating Tolerance and in response to a Markets+ dispatch instruction is considered delivered utilizing Markets+ Transmission Capability.

The use of Markets+ Transmission Capability does not cause any existing transmission reservations to be de-prioritized.

1.1 Limited Markets+ Transmission Service Provider Responsibilities

Markets+ Transmission Service Providers shall have the obligation to make available the otherwise unused physical capability of the transmission facilities under their tariffs for purposes of providing Markets+ Transmission Capability to support the delivery of Energy and to operate the facilities under their tariffs in accordance with Good Utility Practices.

For purposes of Markets+ Transmission Capability, Markets+ Transmission Service Providers shall have no obligation to plan, construct, or maintain their transmission systems for the benefit of Markets+.

1.2 Obligation to Communicate Markets+ Transmission Capacity Availability Changes

Markets+ Transmission Contributors and Markets+ Transmission Service Providers must communicate any changes to the availability of Markets+ Transmission Capability to the Market Operator pursuant to the Markets+ Protocols. Market Participants may update Opt-Outs no more than once per month, with notification no later than fifteen (15) days prior to the start of the upcoming month for which a Markets+ Transmission Capacity Opt-Out will begin, and for the entirety of the one or more calendar months.

1.3 Conditions Precedent for Receiving Markets+ Transmission Capability

Subject to the terms and conditions of this Attachment D of the Tariff, and related attachments, Markets+ Transmission Service Providers will allow use of Markets+ Transmission Capability by any Markets+ Transmission User. Use of Markets+ Transmission Capability is allowed commensurate with energy dispatched within the Markets+ Footprint pursuant to the provisions of this Tariff. As such, the Markets+ Transmission User is not required to separately request or make an application to use Markets+ Transmission Capability. A Markets+ Transmission Service Provider agrees to provide comparable service that it is capable of providing to all Markets+ Transmission Users on similar terms and conditions over facilities used for the transmission of electric energy in interstate commerce owned, controlled, or operated by Markets+ Transmission Service Providers.

No separate charge will be assessed by the Market Operator for the use of Markets+ Transmission Capability beyond the MTU charge as set forth in Section XX, which is not a charge for transmission service.

1.4 Generator Transmission Requirement Review

The Market Operator will undertake a review to determine what, if any, cost shifts have occurred in the absence of a requirement for generators to purchase transmission service to conduct sales in Markets+, after the occurrence of either of the following:

(1) Two (2) years of data needed to conduct the study are available; or

(2) A Markets+ Transmission Service Provider requests such a review following a reduction of at least two percent (2%) of their long-term-firm point-to-point revenues or 2% of their long term firm point-to-point reservations on an annual basis for their transmission facilities as they existed when Markets+ began operations.

This review does not preclude a request for review from Markets+ Participants.

1.5 Obligation to Pause Queue Processing

Markets+ Transmission Service Providers must pause processing of transmission service requests for the upcoming Operating Day between the time the Day-Ahead Market closes, and when Day-Ahead Energy Schedules are updated by the Market Operator. This pause will not affect the prioritization of requests received when queue processing is paused.

ATTACHMENT E
Market Participant Service Agreement

MARKET PARTICIPANT SERVICE AGREEMENT
FOR MARKET PARTICIPANTS IN MARKETS+

1. This Market Participant Service Agreement ("Service Agreement") dated as of _____ is entered into by and between Southwest Power Pool, Inc. ("SPP") and _____ ("Market Participant"). SPP and Market Participant are each sometimes referred to in the Service Agreement as a "Party," and collectively as the "Parties."

2. The Market Participant has submitted an application for participation in Markets+ as part of its registration as a Market Participant in accordance with the market application and registration procedures specified in the Markets+ Tariff (the "Tariff") and Protocols, and has provided the information specified in Appendix 1 to this Service Agreement.

3. The Market Participant understands the Market Operator will use registered Resources and loads and Markets+ transmission capability in the performance of its activities.

4. The Market Participant represents and warrants that it has met or will meet all applicable readiness requirements set forth in the Tariff prior to participation in Markets+.

5. SPP agrees to provide, and the Market Participant agrees to take and pay for, or to supply to SPP, any or all of the products defined in the Tariff in accordance with the Tariff's provisions, and to satisfy all obligations under the terms and conditions of the Tariff and the Protocols.

6. SPP and the Market Participant agree that this Service Agreement shall be subject to, and shall incorporate by reference, all of the terms and conditions of the Tariff.

7. The Market Participant represents and warrants that:

   (a) At any time it has registered one or more Resources, the Market Participant intends to participate in Markets+ in accordance with procedures specified in the Tariff and Protocols, the participation of its Resource(s) in Markets+ is not precluded under the laws or regulations of the relevant electric retail regulatory authority, including state-approved retail tariff(s), and the Market Participant (a) has market-based rate authority from FERC or (b) has another FERC-approved basis for setting prices in Markets+, or (c) is exempt from the requirement to have rates for services on file with FERC;

   (b) This Service Agreement, or any transaction entered into pursuant to the Service Agreement, as applicable, has been duly authorized;

   (c) This Service Agreement is the legal, valid, and binding obligation of the Market Participant, enforceable in accordance with its terms, except as it may be rendered unenforceable by reason of bankruptcy or other similar laws affecting creditors' rights, or general principles of equity;

8. The Market Participant agrees that, during the duration of this Service Agreement, the Market Participant shall be in compliance with all applicable federal, state, and local laws, rules, and regulations related to the Market Participant's performance under this Service Agreement.

9. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below:

SPP: _____

Market Participant: _____

10. Cancellation Rights:

If FERC or any regulatory agency having authority over this Service Agreement determines that any part of this Service Agreement must be changed, SPP shall offer to the Market Participant within fifteen (15) Calendar Days of such determination an amended Service Agreement reflecting such changes. In the event that the Market Participant does not execute such an amendment within thirty (30) Calendar Days of receipt of an amended Service Agreement from SPP, or longer if the Parties mutually agree to an extension, such agreement shall not be unreasonably withheld, conditioned, or delayed, this Service Agreement and the amended Service Agreement shall be void.

11. Termination:

(a) The Market Participant may terminate service under this Service Agreement no earlier than ninety (90) Calendar Days after providing SPP with written notice of the Market Participant's intention to terminate. The Market Participant's provision of notice to terminate service under this Service Agreement shall not relieve the Market Participant of its obligation to pay any rates, charges, or fees due under this Service Agreement that are owed as of the date of termination.

(b) SPP may terminate service under this Service Agreement if the Market Participant is in default, such default condition as defined under Article 8 of Attachment H to this Tariff, in accordance with the procedures specified under Attachment I to this Tariff and Section 9.12 of Attachment A to this Tariff, as applicable.

12. The Market Participant agrees to pay all amounts due and chargeable to the Market Participant and SPP agrees to pay all amounts creditable to the Market Participant in accordance with the terms of the Tariff.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

SPP:	**Market Participant:**
By: _____	**By: _____**
Printed Name: _____	**Printed Name: _____**
Dated: _____	**Dated: _____**
Title: _____	**Title: _____**

Appendix 1 to Attachment E

MARKET PARTICIPANT INFORMATION:

Requested Change Type [1] (Add, Modify, Terminate)	Market Participant Name [2]	Market Participant Acronym [3] (4 characters)	Registered in EIR? [4] (yes/no)	Credit Customer Name[5]

ASSET OWNER INFORMATION:

Requested Change Type [1] (Add, Modify, Terminate)	Asset Owner Name [6]	Asset Owner Acronym [7] (4 characters)	Registered in EIR? [8] (yes/no)	Resource Owner [9] (yes/no)	Load Serving Entity [10] (yes/no)

METER AGENT INFORMATION:

Requested Change Type [1] (Add, Modify, Terminate)	Meter Agent Name [12]	Meter Agent Acronym [13] (4 characters)	Registered in EIR? [14] (yes/no)

CONTACT INFORMATION:

Contact Last Name	Contact First Name	Contact Type[15] (A,B,C)	Phone Number (nnn) nnn-nnnn	Email Address

PROPOSED EFFECTIVE DATE[16]: _____

Instructions for Populating Appendix 1 Tables

1 **Requested Change Type –** Indication of the type of change for each record. For adding an entity or relationship this will be Add. To terminate an entity or relationship from Markets+, enter Terminate. For requesting a modification or name change of an entity, enter Modify. When requesting a name change to an entity, enter the existing name followed by a forward slash "/" and then the new name.

2 **Market Participant Name -** Full name of the Market Participant.

3 **Market Participant Acronym** - The NAESB Electric Industry Registry ("EIR") acronym that will be used for the Market Participant. If the entity is not registered in the EIR, the acronym should conform to the EIR format of no more than four (4) alpha numeric characters. Any acronym for an entity that is not registered in EIR must also be unique from any abbreviation that is registered in EIR by another party.

4 **Registered in EIR –** Enter "yes" if the entity is registered at EIR.

5 **Credit Customer Name -** The name of the entity that will be providing secured and unsecured credit for the Market Participant's activities in Markets+ in accordance with Attachment H of this Tariff.

6 **Asset Owner Name** - The name of the Asset Owner that is registered by the Market Participant.

7 **Asset Owner Acronym** - The Asset Owner acronym abbreviation that will be used for this Asset Owner will be the same as the acronym in the EIR if the entity is registered in the EIR. If the entity is not registered in the EIR, the abbreviated name should conform to the EIR format of no more than four (4) alpha numeric characters. Any abbreviation for an entity not registered in the EIR must also be unique from any abbreviation that is registered in the EIR by another party.

8 **Registered in EIR? -** This field is used to identify if the entity is registered at EIR. For Asset Owners not registered at EIR, the Market Operator will validate the acronym used is not registered at EIR by another party currently. To ensure uniqueness against EIR in the future, the Market Operator will also append "_X" to the Asset Owner Acronym supplied for those that are not registered.

9 **Resource Owner -** This is a Yes or No answer indicating whether or not the Asset Owner is a Resource owner and will be registering Resources to participate in the Energy and Flexibility Reserves Market.

10 **Load Serving Entity** - This is a Yes or No answer indicating whether or not the Asset Owner is a Load Serving Entity and will be registering Load Assets to be supplied in the Energy and Flexibility Reserves Market.

11 **Meter Agent Name -** Any Market Participant with load and/or Resources will either be a Meter Agent or have a relationship with at least one Meter Agent. Identify the Meter

Agent(s) registered with the Market Operator that will be responsible for the acquisition of end-use meter data, aggregation of meter data, application of data to Settlement Intervals, and transfer of meter data to the Market Operator on behalf of this Market Participant. This entity can be a traditional utility entity or other competitive entity. If the Market Participant is not acting as its own Meter Agent, show the Meter Agent as the Entity's name as it is registered on the Meter Agent Agreement form in Attachment G of the Tariff.

12 **Meter Agent Acronym -** The abbreviation that will be used for this Meter Agent which agrees with EIR if the Entity is registered in the EIR. If the entity is not registered in the EIR, the abbreviated name should conform to the EIR format of no more than four (4) alpha numeric characters. Any abbreviation for an entity not registered in EIR must be unique from any abbreviation that is registered in EIR by another party.

13 **Registered in EIR -** This field is used to identify if the entity is registered in the EIR. For Meter Agents not registered in the EIR, the Market Operator will validate the acronym used is not registered in the EIR by another party currently. To ensure uniqueness against EIR in the future, the Market Operator will also append "_X" to the Meter Agent Acronym supplied for those that are not registered.

14 **Contact Type** - Specific points of contact for each Market Participant for questions regarding the Network and Commercial Models as well as a primary market operations contact for the Market Participant.

Type A - Primary market operations and Commercial Model point of contact - required

Type B - EMS and ICCP contacts - required for MPs with physical assets.

Type C - Secondary market operations contacts - optional.

15 **Proposed Effective Date:** The date on which the Market Participant would like these changes to be effective in the Market Operator's models and systems.

ATTACHMENT F
Form of Non-Disclosure Agreement for Authorized Requestors

THIS NON-DISCLOSURE AGREEMENT (the "Agreement") is made this ___ day of ___ by and between, _____, an Authorized Agency, as defined below, with offices at _____, and Southwest Power Pool, Inc., an Arkansas not for profit corporation, with offices at 201 Worthen Drive, Little Rock, Arkansas 72223-4936 ("SPP" or "Market Operator"). The Authorized Agency and SPP shall be referred to herein individually as a "Party," or collectively as the "Parties." Unless otherwise stated herein, capitalized terms shall have the same meaning as set forth in Section 1 of the Tariff on file with the Federal Energy Regulatory Commission (FERC).

RECITALS

Whereas, the Market Operator operates and oversees certain wholesale markets for electricity in the Markets+ Footprint pursuant to the requirements of this Tariff; and

Whereas, the Market Monitor serves as the monitor for certain wholesale markets for electricity in the Markets+ Footprint as specified in the Tariff; and

Whereas, Attachment A to the Tariff requires that Market Operator and the Market Monitor maintain the confidentiality of Confidential Information; and

Whereas, Section 10.4 of Attachment A to the Tariff enables Market Operator and the Market Monitor to disclose Confidential Information to the Authorized Agency, through its Authorized Requestor(s), upon satisfaction of conditions stated in Attachment A to the Tariff, including the execution of this Agreement by the Authorized Agency and of Attachment F - Form B by the Authorized Requestor(s);

Whereas, the Market Operator intends to provide the Authorized Agency, through its Authorized Requestor(s), with access to Confidential Information, consistent with the Market Operator's and the Market Monitor's obligations and duties under the Tariff and applicable law; and

Whereas, this Agreement is a statement of the conditions and requirements, consistent with the requirements of Attachment A to the Tariff, whereby the Market Operator or the Market Monitor

shall provide Confidential Information to the Authorized Agency through its Authorized Requestor(s).

NOW, THERFORE, agreeing to be legally bound, the Parties hereby agree as follows:

1. Definitions. To the extent the below definitions conflict with the Tariff, the Tariff shall control.

1.1 Authorized Agency. (i) a State public utility commission within the geographic limits of the Market+ Footprint that regulates the distribution or supply of electricity to retail customers or is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers; (ii) the Markets+ State Committee or any successor organization formed to act as a regional state committee within Markets+; or (iii) a state agency that has both access to documents in the possession of a state public utility commission pursuant to state statute and the ability to protect those documents in accordance with the Non-Disclosure Agreement.

1.2 Authorized Requestor. An individual who has executed the Acknowledgement of Non-Disclosure Agreement for Authorized Requestors in the form outlined in Attachment F - Form B and is authorized by an Authorized Agency to receive and discuss Confidential Information on behalf of the Authorized Agency.

1.3 Confidential Information. Information containing or revealing:

Any proprietary or commercially or competitively sensitive information, trade secret or information regarding a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Market Participant, which is designated as confidential by that Market Participant when supplying the information to the Market Operator, whether conveyed orally, electronically, in writing, through inspection, or otherwise; or

Any software, products of software or other vendor information that SPP is required to keep confidential under its agreements.

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

Controlled Unclassified Information ("CUI"), which is unclassified information that requires safeguarding or dissemination controls pursuant to and consistent with applicable law, regulations, and government-wide policies.

1.4 Information Request. A written request in accordance with the terms of this Agreement for disclosure of Confidential Information pursuant to Section 10.4 of Attachment A to the Tariff.

1.5 Markets+ Footprint. The geographic region defined by the Balancing Authorities participating in Markets+ under the Tariff.

1.6 Market Monitor. The Market Monitoring Unit established under the Tariff.

1.7 Tariff. The Markets+ Tariff, including all schedules and attachments thereto, of the Market Operator as amended from time to time.

1.8 Third Party Request. Any request or demand by any entity upon an Authorized Agency or any of its Authorized Requestors for release or disclosure of Confidential Information. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, request pursuant to state freedom of information or public records access statutes or regulations, or other request for Confidential Information made by any: (i) federal, state or local government subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual. This provision is subject to any applicable exception under Attachment A to the Tariff.

2. Protection of Confidentiality.

2.1 Representation as to Status and Acceptance of Duty to Not Disclose.

The Authorized Agency states that: (a) it is an Authorized Agency as defined herein; (b) it has practices or procedures adequate to protect against the unauthorized release of Confidential Information received; (c) it will deny Third Party Requests and defend, consistent with the terms of Section 2.3.6 below, against any legal process that seeks the release of any Confidential Information in contravention of the terms of this Agreement; and (d) it is not in breach of any non-disclosure agreement entered into with Market Operator. The Authorized Agency also states that it will act consistently with the representations and confirmations made to the Market Operator and will fully comply with any other terms of Section 10 of Attachment A of the Tariff.

2.2. Conditions Precedent.

The Authorized Agency shall, prior to the initial Information Request for Confidential Information by an Authorized Requestor on its behalf, provide the Market Operator with information and documents required of the Authorized Agency and its Authorized Requestor(s) under the Tariff.

2.3 Care and Use of Confidential Information.

2.3.1 Control of Confidential Information. The Authorized Agency shall be the custodian of any and all Confidential Information received pursuant to the terms of this Agreement from the Market Operator or the Market Monitor.

2.3.2 Access to Confidential Information. The Authorized Agency shall ensure that Confidential Information received by the Authorized Agency and its Authorized Requestor(s) is disclosed only as allowed under Section 10 of Attachment A of the Tariff.

2.3.3 Notice of Change in Status. The Authorized Agency shall promptly notify the Market Operator of any change that would affect the Authorized Agency's status as an Authorized Agency or the Authorized Requestor's status as an Authorized Requestor.

2.3.4 Use of Confidential Information. The Authorized Agency shall ensure that Confidential Information received by the Authorized Agency, through its Authorized Requestor(s), is used only as provided in Section 10 of Attachment A of the Tariff.

2.3.5 Return of Confidential Information. When the Authorized Agency determines that it no longer needs the Confidential Information that was disclosed to the Authorized Requestor (*e.g.*, if for any reason the Authorized Requestor is not, or will no longer be an Authorized Requestor, and/or the Confidential Information they received is no longer needed by the Authorized Agency), the Authorized Agency or Authorized Requestor shall: (a) return the Confidential Information and all copies thereof to the Market Operator or the Market Monitor, or (b) certify to the Market Operator or the Market Monitor that all paper copies have been destroyed and all electronic copies of the Confidential Information have been deleted, or (c) identify the time by which it will comply with either (a) or (b) above consistent with state document retention laws. The Market Operator or the Market Monitor shall waive this condition in writing if such Confidential Information has become publicly available or non-confidential in the course of business or pursuant to the Attachment A to the Tariff or applicable rule or order of the FERC.

2.3.6 Defense Against Third Party Requests

2.3.6.1 The Authorized Agency will deny any Third Party Requests for which it or its Authorized Requestor is not legally compelled to comply. For any other Third Party Requests made to the Authorized Agency or its Authorized Requestor(s), the Authorized Agency will defend against any such Third Party Requests by seeking to obtain any necessary protective orders. The Authorized Agency shall provide the Market Operator with prompt notice of any such Third Party Request or legal proceedings, and shall consult and cooperate with Market Operator in its efforts to deny the request or defend against such legal process. In the event a requested protective order or other remedy is denied, and the Authorized Agency or its Authorized Requestor(s) are legally compelled to furnish Confidential Information, Authorized Agency agrees to (and cause its Authorized Requestor to) furnish only the portion of the Confidential Information which the Authorized Agency's legal counsel advises the Market Operator in writing is legally required to be furnished.

2.3.6.2 In the event that counsel for the Authorized Agency discloses a state law that prohibits or prevents the Authorized Agency from defending against any disclosure of Confidential Information, the Authorized Agency will be excused from the obligation to defend in Section 2.3.6.1, including, but not limited to, obtaining any necessary protective orders.

2.4 Ownership and Privilege. Nothing in this Agreement, or incident to the provision of Confidential Information to the Authorized Requestor pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Information is intended or shall be inferred by the disclosure of Confidential Information by the Market Operator or by the Market Monitor, and any and all intellectual property comprising Confidential Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of SPP, Market Monitor, the affected Market Participant, and/or other owner(s) thereof.

3. Unauthorized Disclosure and Remedies for Breach of Agreement

3.1 Notification of Unauthorized Disclosure to Third Parties. As provided in the Tariff, the respective Authorized Agency shall promptly notify the Market Operator or the Market Monitor,

who shall, in turn, notify any affected Market Participant of any unauthorized release of Confidential Information provided pursuant to any non-disclosure agreement. The Authorized Agency shall take steps to minimize any further release of Confidential Information, and shall take reasonable steps to attempt to retrieve any Confidential Information that may have been released.

3.2 Breach. The Authorized Agency agrees that its release of Confidential Information to persons that have not executed Attachment F – Form B constitutes a breach of this Agreement, unless the Authorized Agency is required under state or federal law to release such information. If the Market Operator or the Market Monitor determines on its own, or agrees with an Authorized Agency, or receives from an Authorized Requestor or Authorized Agency a written notice, that a breach has occurred, or FERC has made a ruling that a breach has occurred, the Market Operator and/or the Market Monitor may terminate the Agreement and require either (1) the immediate return of all Confidential Information obtained by the Authorized Agency through its Authorized Requestor(s), (2) a certification of its destruction, or (3) a showing that retention for a specified amount of time is required under applicable law.

4. Notices. All notices required pursuant to the terms of this Agreement shall be in writing, and served upon the following individuals in person, or at the following addresses or email addresses:

If to the Authorized Agency:
_____
_____
_____
_____
(email address)
with a copy to
_____
_____
_____
_____
(email address)
If to SPP:
_____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
(email address)
with a copy to

_____
_____
_____
_____
(email address)

If to the Market Monitor:

_____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
(email address)
with a copy to

_____
_____
_____
_____
(email address)

5. Severability and Survival. In the event any provision of this Agreement is determined to be unenforceable as a matter of law (including state Freedom of Information Act statutes), all other provisions of this Agreement will remain in full force and effect in accordance with their terms. In the event of conflicts between the terms of this Agreement and the Tariff, the terms of the Tariff shall in all events be controlling. The Authorized Agency acknowledges that any and all obligations of the Authorized Agency hereunder shall survive the severance or termination of any employment or retention relationship between the Authorized Requestor and its respective Authorized Agency.

6. Representations. The undersigned is able to perform all of the obligations and duties contained herein.

7. Counterparts. This Agreement may be executed in counterparts and all such counterparts together shall be deemed to constitute a single executed original.

8. Amendment. This Agreement may not be amended except by written agreement executed by authorized representatives of the Parties.

9. Assignment. This Agreement is not assignable without the written agreement of both Parties.

Southwest Power Pool, Inc.

By: _____
Printed Name: _____
Title: _____
Date: _____

Authorized Agency

By: _____
Printed Name: _____
Title: _____
Date: _____

ATTACHMENT G

Meter Agent Services Agreement
FOR MARKETS+ BETWEEN MARKET PARTICIPANT AND METER AGENT
(DATE)

This Meter Agent Services Agreement ("Agreement"), made and entered this __ day of _____, _____, is between _____ ("Market Participant") and _____ ("Meter Agent"). Market Participant and Meter Agent are each sometimes referred to in the Agreement as a "Party" and collectively as the "Parties."

The parties mutually agree as follows:

ARTICLE I
Responsibilities of the Parties

1.1 **Market Participant Responsibilities:**

1. **Governing Documents:** In addition to this Agreement, Market Participant agrees that it will comply with the provisions of the Markets+ Tariff ("Tariff") and Markets+ Protocols as they may be amended from time to time which relate to implementation of this Agreement. In the event there is a conflict between this Agreement and the Tariff, the Tariff shall govern.

2. **Data Communications:** Market Participant shall provide or arrange for communication of meter data in a mutually acceptable format to the Meter Agent.

3. **Meter Data Submittal Location:** Market Participant shall provide in Exhibit A the meter(s) and calculations used to calculate the Meter Data Submittal Location value.

4. **Notice of Meter Changes:** Market Participant shall inform the Meter Agent of any additions, deletions, and modifications to metering that will impact the market data.

a. Market Participant shall provide full metering information to the Meter Agent a minimum of sixty (60) Calendar Days prior to the implementation of a change, except when the meter equipment is changed or replaced due to equipment failure, in which case notice of change will be provided as soon as possible. Information to be provided shall include:

1. Information relating to retrieval of the meter data from the data source, communications, and full description of the meter.
2. Information relating to the data and its processing that will be applied for the new or modified Meter Data Submittal Location and the impact to other existing Meter Data Submittal Location or tie-line flow between Settlement Areas.
3. Completing Markets+ registration, which includes real-time data exchange and modeling coordination with SPP.
4. Updating of Exhibit A.

b. In addition, Market Participant shall be responsible for developing and testing a complete system for submission of data under this Agreement.

c. Market Participant shall notify Meter Agent of any significant metering issues related to the data provided to the Meter Agent within twenty four (24) hours after the issue is identified. This includes change out of a meter, meter failures, real-time data failures, etc.

5. **Meter Data Submittal Location Notification:** Market Participant shall notify any other Market Participant affected by the change, if known, in the Meter Data Submittal Location at least seven (7) Calendar Days prior to the change.

6. **Data Exchange and Data Quality:** Market Participant shall provide meter data for each meter identified in Exhibit A to the Meter Agent in a timely manner.

a. Data shall be provided to the Meter Agent at least one (1) full Business Day prior to SPP's deadline for submission of meter data, as the deadline is specified in the Markets+ Protocols.

b. Upon notification to or upon discovery by the Market Participant that the data exchange has failed or data quality is questionable, the Market Participant will resolve the issue at its source.

c. In the absence of actual values for data required for settlement, it is the Market Participant's responsibility to provide estimated values for such data to the Meter Agent; however, if the Market Participant fails to provide the actual or estimated meter data in a timely manner, the Meter Agent will estimate the data for submission to SPP by the appropriate deadline. The Meter Agent will be held harmless as set forth in Section 3.2 of this Agreement.

7. **Submission Failures:** If the Meter Agent fails to submit the meter data, including Settlement Area tie-line meter data by the Final Settlement Statement data cutoff, the Market Participant is responsible for initiating and pursuing resolution.

1.2 **Meter Agent Responsibilities:**

1. **Governing Documents:** In addition to complying with this Agreement, Meter Agent shall provide services on behalf of the Market Participant in accordance with the Tariff and Markets+ Protocols as they may be amended from time to time related to implementation of this Agreement. In the event there is a conflict between this Agreement and the Tariff, the Tariff shall govern.

2. **Meter Agent Registration:** Meter Agent shall be a registered Meter Agent in Markets+.

3. **Meter Data Submittal Location Development:** Meter Agent shall provide all settlement data required for the Meter Data Submittal Locations designated by the Market Participant in Exhibit A.

4. **Data Communications:** Meter Agent and the Market Participant shall mutually agree upon a format and method of exchange of settlement data required to be provided by the Market Participant.

5. **Meter Data Submittal Location Values:** Meter Agent shall determine the meter value for each of the Meter Data Submittal Location identified in Exhibit A by applying all parameters as identified therein.

6. **Data Issue Notifications:**

a. Meter Agent will notify the Market Participant, as soon as practicable, of any data exchange issues with the meter data source.

b. Upon failure to receive meter data from the Market Participant by the data submission deadline, the Meter Agent will notify the Market Participant as soon as practicable and, if necessary, the Meter Agent will estimate the data pursuant to Section 1.1(6)(c) of this Agreement.

7. **Data Submission:** Meter Agent shall submit Meter Data Submittal Location meter values to the Market Operator by the deadlines outlined in the Markets+ Protocols.

ARTICLE II
Term and Termination

2.1 **Initial Term:** This Agreement shall become effective on _____, _____ and shall continue until _____, _____.

2.2 **Extended Term:** This Agreement shall continue on a year-to-year basis at the conclusion of its Initial Term, unless terminated as specified in the Agreement.

2.3 **Termination:** This Agreement may be terminated at any time by mutual agreement of the Market Participant and Meter Agent. Either the Market Participant or the Meter Agent may terminate the Agreement after the Initial Term, upon giving sixty (60) Calendar Days prior written notice to the other Party.

ARTICLE III
Miscellaneous

3.1 **Force Majeure:** An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, cyberattack, riot, pandemic, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation, or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither Party will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Agreement is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff. A Party that has experienced a Force Majeure event must notify the other Party as soon as practicable and identify the Force Majeure event and the obligations affected by the event.

3.2 **Indemnification:** To the extent permitted by the Tariff, each Party hereto shall indemnify and hold harmless the other Party (in such case, the "Indemnified Party"), its officers, directors, agents and employees from and against any and all claims for death or injury to persons or destruction of or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney's fees, and all other obligations by or to third parties (collectively "liabilities"), arising out of or resulting directly or indirectly from the Indemnified Party's performance of its obligations under this Agreement on behalf of the Indemnifying Party, except to the extent any such liability arises, directly or indirectly, from the Indemnified Party's gross negligence or intentional wrongdoing. For example, the provisions of this section 3.2 could apply in circumstances where equipment malfunction (or other inadvertent error not involving gross negligence or intentional wrongdoing) causes metered information to be inaccurately reported, resulting in billing errors.

3.3 **Successors and Assignment:** This Agreement shall be binding upon the Parties and their respective successors and assigns. This Agreement shall not be assignable by either Party except with the prior written consent of the other Party which shall not be unreasonably withheld.

3.4 **Good Utility Practices:** The Parties shall conduct their affairs under this Agreement in accordance with Good Utility Practices. Good Utility Practices shall mean any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, safety, and expedition. Good Utility Practices is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts, generally accepted by the region.

3.5 **No third-party beneficiaries.** There shall be no third-party beneficiaries to this Agreement.

3.6 **Amendment:** The Parties may, by mutual agreement, amend Exhibit A or Article II of this Agreement by a written instrument duly executed by each of the Parties.

3.7 **Notification to SPP**: The initial Agreement and any amendments thereto shall be provided to SPP upon execution.

ARTICLE IV
Notices

4.1 **Agreement Notices:** Any notice, demand or request required or authorized by this Agreement shall be deemed properly made, given to, or served on the party to whom it is directed when sent by written notification, whether by electronic mail or regular mail, addressed as follows:

Market Participant:	**Meter Agent:**
Title	Title
Company	Company
Address	Address
City, State, Zip	City, State, Zip
Email	Email

Notice of change in the above addresses shall be given in the manner specified above.

ARTICLE V
Complete Agreement

5.1 **Complete Agreement:** This Agreement represents the Parties' final and mutual understanding concerning its subject matter. It replaces and supersedes any prior agreements or understandings, whether written or oral. No representations, inducements, promises, or agreements, oral or otherwise, have been relied upon or made by either Party, or anyone on behalf of a Party, that are not fully expressed in this Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized officers as of the day and year first above stated.

Printed Name: _____

Market Participant: Title :_____

Company: _____

By: _____ **Meter Agent:**

Company: _____

By: _____

Printed Name: _____

Title :_____

Exhibit A

Market Participant Meter Data Submittal Location Definitions

Resource Meter Locations:

#	Meter Data Submittal Location Name	Meter	Physical Location	Voltage Level	Losses	Operand

Gross Generation output is negative, auxiliary use is positive. MWh received by the Transmission System is negative.

Load Meter Data Submittal Locations: (Name of Location)

#	Meter Data Submittal Location Name	Meter	Physical Location	Voltage Level	Distrib. Losses	*	Operand

** Engineered Adjustment with Assumption – reference SPP Markets+ Protocols

Residual Load Meter Data Submittal Locations:

#	Meter Data Submittal Location Name	Meter	Operand

Assumes sign of other Meter Data Submittal Location data used is in polarity required for submission to SPP Market.

Tie-Line Meter data between Settlement Areas:

#	Tie-Line Meter Name	Meter	Operand

ATTACHMENT H
Credit Policy

ARTICLE ONE

General Provisions

1.1 Policy Statement. In furtherance of competition and the orderly administration of the Markets+ Tariff (the "Tariff"), Southwest Power Pool ("SPP") shall administer, implement and enforce this Credit Policy. This Credit Policy is intended to encourage the maximum participation of large and small participants in all market sectors while minimizing the likelihood of losses due to default and to establish eligibility requirements for market participation.

1.2 Applicability of Credit Policy and Overview.

1.2.1 This Credit Policy is applicable to each Credit Customer. It applies to each Credit Customer regardless of whether SPP previously extended credit to, or established a Total Credit Limit for, the Credit Customer.

1.2.2 As a condition to taking any service subject to this Credit Policy, SPP must determine that the Credit Customer satisfies SPP's credit requirements and minimum criteria for market participation under this Credit Policy and the terms and conditions for an extension of credit. SPP's determination is a Credit Assessment. The Credit Assessment is based upon quantitative and qualitative credit scoring under the formulae and procedures set forth in this Credit Policy. This Credit Policy provides for initial and ongoing Credit Assessments. In order to facilitate continuous evaluation of credit, it requires the submission of Credit Information to SPP periodically and, additionally, upon the occurrence of certain events. Based upon the ongoing Credit Assessment, SPP is authorized, at any time, to revise a Credit Customer's Total Credit Limit and the terms and conditions for the extension of credit.

1.2.3 SPP shall conduct initial and ongoing Credit Assessments for each Credit Customer, based, as applicable, upon the Credit Application, Credit Information, and Credit Ratings. Credit Information includes: (a) the information contained in and submitted with the Credit Customer's duly executed Credit Application; and (b) updated and additional information the Credit Customer is required to submit from time to time under this Credit Policy. Credit Information and Credit Ratings, if any, shall be sufficient to enable SPP to determine under this Credit Policy whether to approve an extension of credit, and the amount, terms, and conditions thereof, including the extent and nature of any Guaranty or Financial Security.

1.2.4 Based upon its Credit Assessment, SPP will: (a) determine the Credit Customer's Total Potential Exposure; (b) determine the amount of credit the Credit Customer requires; (c) determine whether to grant, and the amount of, any Unsecured Credit Allowance; (d) evaluate any Guaranty the Credit Customer offers to provide,

including a Credit Assessment for the proposed Guarantor; (e) determine the amount of any required Financial Security; and (f) determine if the Credit Customer meets the minimum criteria for market participation under Sections 3.1.1.8 and 3.1.1.9. Based on these determinations, which shall include consideration of the Credit Customer's ability to fulfill SPP's requirements to obtain credit, SPP will set the Total Credit Limit for the Credit Customer.

1.2.5 To facilitate the Credit Assessment, each Credit Customer shall submit a duly executed Credit Application in the form attached as Appendix "A," and the Credit Information required under this Credit Policy. If SPP determines that an extension of credit to a Credit Customer must be supported by Financial Security, the Credit Customer shall, upon SPP's request, duly execute the Credit and Security Agreement in the form attached as Appendix "B." . Any Irrevocable Letter of Credit shall be substantially in the form attached as Appendix "C," any Guaranty shall be substantially in the form attached as Appendix "D," and any Surety Bond shall be substantially in the form attached as Appendix "F." Any variations in the forms of Credit and Security Agreement, Irrevocable Letter of Credit, Guaranty, or Surety Bond must be approved by SPP, and may not materially modify or impair SPP's rights under such form, in SPP's sole discretion.

1.3 Components of Credit Policy. This Credit Policy includes the following elements:

1.3.1 Requirements for the establishment and maintenance of credit applicable to Credit Customers.

1.3.2 The basis for establishing a Total Credit Limit for a Credit Customer in order to extend credit, but diminish the possibility of failure of payment under the Tariff and Agreements.

1.3.3 Forms of Guaranty and Financial Security acceptable to SPP, to be provided if SPP does not approve an Unsecured Credit Allowance sufficient to cover the Credit Customer's Total Potential Exposure.

1.3.4 Requirements to facilitate ongoing Credit Assessments.

1.3.5 Specification of Defaults under this Credit Policy and remedies.

1.3.6 Minimum criteria for market participation.

1.4 Fairness, Objectivity, and Non-Discrimination. SPP will seek and receive information and explanation from a Credit Customer as appropriate to help ensure that the Credit Assessment is fair and thorough. SPP will base each Credit Assessment upon SPP's evaluation of the Credit Information, Credit Ratings, and other pertinent indicators of financial strength identified under this Credit Policy. SPP shall make each Credit

Assessment objectively and without undue discrimination in favor of or against any market sector. Whenever this Credit Policy permits SPP to exercise discretion in the implementation of the provisions of this Credit Policy, SPP shall exercise that discretion in a fair and impartial manner that treats all Credit Customers in a non-discriminatory manner.

1.5 Construction and Interpretation.

1.5.1 The word "including" shall be understood to mean "including without limitation." The singular form of a word shall be understood to include the plural form, and vice versa, as appropriate to implement the applicable term or condition.

1.5.2 Except as otherwise stated, the words "Section" and "Article" refer to sections and articles of this Credit Policy. A Section reference includes all subsections and subparts of the Section.

1.5.3 All references to amounts of cash, cash deposits, and to monies paid, provided, due or otherwise, shall be construed to refer to United States dollars.

1.6 Disputes. Any disputes arising under this Credit Policy will be subject to the dispute resolution procedures set forth in Section 6 of the Tariff.

ARTICLE TWO

Definitions

2.1 Definitions. The following definitions apply in this Credit Policy. Capitalized terms used herein and not defined herein shall be given the meaning assigned to them under the Tariff.

Affiliate
A business concern, organization, or individual is an affiliate of another business concern, organization, or individual, including a Credit Customer, that directly or indirectly: (a) has the power to control or is controlled by it; or (b) is under common control of a third party. Elements of control include interlocking management or ownership, shared facilities and equipment, and common use of employees.

Affiliated Credit Customers
Credit Customers that are Affiliates.

Agreements
The Tariff, including this Credit Policy, any and all agreements entered into by the Credit Customer under, pursuant to or in connection with the Tariff and/or this Credit Policy, and any and all other Agreements to which SPP and the Credit Customer are both parties.

Cash Deposit
Cash collateral provided to SPP to secure a Credit Customer's performance under the Tariff, this Credit Policy, and/or any other Agreements, and any other cash to which the Credit Customer has title or rights in the possession of SPP (cash SPP has applied to payment of an obligation under the Tariff or Agreements is not cash to which a Credit Customer has title or rights).

Composite Credit Score or Credit Score
This term shall have the meaning given in Section 4.2 of this Credit Policy.

Credit and Security Agreement
A legal document, outlining certain terms pursuant to which a security interest in certain collateral is granted to SPP, in the form incorporated herein as Appendix "B".

Credit Application
The completed, executed, and submitted Credit Application in the form attached as Appendix "A" hereto, together with the Credit Information required under this Credit Policy.

Credit Assessment
This term shall have the meaning given in Article Three.

Credit Contact
This term shall have the meaning given in Section 9.1.

Credit Customer
Any person who takes or seeks to take service under the Tariff.

Credit Information
This term shall have the meaning given in Section 1.2.3.

Credit Ratings
Rating assigned by a Rating Agency based on an obligor's creditworthiness to pay financial obligations.

Default or Event of Default
Any default under Article Eight or otherwise under this Credit Policy.

Estimated Virtual Exposure ("EVE")
This term shall have the meaning given in Section 4A.2.

Federal Power Marketing Agency
For purposes of this Credit Policy, this term shall have the same definition that is set forth in the Federal Power Act at 16 U.S.C. § 796(19), which defines a "Federal power marketing agency" as "any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy[.]"

Financial Security
A Cash Deposit, Irrevocable Letter of Credit, Surety Bond, or Federal Power Marketing Agency Letter in amount and in forms as described in Article Seven of this Credit Policy, provided by a Credit Customer to SPP as security.

Financial Statements
This term shall have the meaning given in Section 3.1.1.1.

Guarantor
An entity that guarantees the obligation of another entity under a Guaranty.

Guaranty
A legal document used by an Affiliate of a Credit Customer pursuant to Article Six to guarantee the obligations of such Credit Customer for the benefit of SPP.

Irrevocable Letter of Credit
An irrevocable standby letter of credit, with SPP as beneficiary, substantially in the form attached as Appendix "C" to this Credit Policy and acceptable to SPP.

Large Company Credit Customers or Large Company

This term shall have the meaning given in Section 4.2.1.

Market Exposure
This term has the meaning given in Section 5.2.1.

Material
The lesser of (i) an amount that equals or exceeds five percent (5%) of the Credit Customer's Tangible Net Worth using the last audited financial statements, calculated in accordance with generally acceptable accounting principles; and (ii) a change, event, proceeding, or other occurrence, that results (or if adversely determined could result) in a change of five percent (5%) or more in the Credit Customer's Tangible Net Worth compared to the Tangible Net Worth of the Credit Customer using the last audited financial statements, calculated in accordance with generally acceptable accounting principles.

Material Adverse Change
This term shall have the meaning given in Section 3.2.7.

Not-For-Profit Credit Customers or Not-For-Profit
This term shall have the meaning given in Section 4.2.3.

Peak Market Activity Day
The day in which a Credit Customer's calculated charges owed to SPP are the greatest, over a specified period.

Potential Exposure Window
The number of days of credit exposure for a Credit Customer equal to the sum of days of service that have been invoiced but not paid, days of service that have been calculated but not invoiced, days of service in the cure period, and days before service can be terminated.

Qualitative Score
This term has the meanings applicable under Article Four.

Quantitative Score
This term has the meanings applicable under Article Four.

Rating Agency
S&P Global Ratings (or its successor) ("S&P"), Moody's Investor Services, Inc. (or its successor) ("Moody's"), Fitch Ratings, Inc. (or its successor) ("Fitch") or other "Nationally Recognized Statistical Rating Organization" as defined by the US Securities and Exchange Commission.

SEC
The Securities and Exchange Commission.

Small Company Credit Customers or Small Company
This term shall have the meaning given in Section 4.2.2.

Surety Bond
A surety bond, with SPP as beneficiary, substantially in the form attached as Appendix "F" to this Credit Policy and acceptable to SPP.

Tangible Net Worth
This term shall have the meaning given in Section 4.3.

Total Credit Limit
This term shall have the meaning given in Section 4.5.

Total Potential Exposure or TPE
SPP's estimate of the Credit Customer's current or anticipated transaction activity and resulting obligations for all services under the Tariff or otherwise.

Total Potential Exposure Violation
This term shall have the meaning given in Section 5.4.1.

Unsecured Credit Allowance
This term shall have the meaning given in Section 4.3.

Virtual Energy Bid
This term shall have the meaning given in Attachment A of the Tariff.

Virtual Energy Offer
This term shall have the meaning given in Attachment A of the Tariff.

ARTICLE THREE

Credit Assessment

3.1 Minimum Criteria for Market Participation and Initial Credit Assessment.

3.1.1 Credit Application and Credit Information. A Credit Customer must submit a completed and duly executed Credit Application. The Credit Application shall be renewed and updated for each successive year and shall be submitted to SPP no later than April 30 of each year. A completed Credit Application includes submission of the Credit Application form (Appendix "A"), all information required under Section 3.1.1, and additional information that SPP may request. The Credit Customer must submit the following information with its Credit Application.

3.1.1.1 Audited Financial Statements and Related Information. All annual Financial Statements submitted must be audited. Financial Statements are the following**:**

a. If the Credit Customer is subject to SEC reporting requirements, Financial Statements are:

i. Annual Reports on Form 10-K for the three fiscal years most recently ended, together with any amendments thereto;

ii. Quarterly Reports on Form 10-Q for each completed fiscal quarter of the then current fiscal year, together with any amendments thereto; and

iii. Form 8-K reports, if any, filed after the most recent Form 10-K.

b. If the Credit Customer is not subject to SEC reporting requirements, Financial Statements are:

i. For each of the three fiscal years most recently ended, the Independent Auditor's Report, or similarly named report from the independent auditor which includes the auditor's opinion on the state of the underlying financial statements (for each of the three fiscal years most recently ended); and audited financial statements, including balance sheet, income

statement, statement of cash flow, and statement of stockholder's equity;

ii. For each completed fiscal quarter of the then current fiscal year; financial statements as described in (i) above. Unaudited quarterly financial statements are acceptable.

iii. Notes to financial statements;

iv. Management's discussion and analysis, if any; and

c. The Credit Customer may submit Financial Statements by informing SPP, in writing, where the Financial Statements can be retrieved through the internet. Successful retrieval by SPP will satisfy the Financial Statements submission requirements of this Section. If SPP is not satisfied with the retrieval through the internet, it may require the Credit Customer to submit Financial Statements in hard copy form.

d. In the event any parts of the Financial Statements required under this Section are inapplicable to the Credit Customer, SPP may specify alternate requirements. SPP may request additional Financial Statements and related information at its sole discretion.

e. For Not-For-Profit Credit Customers, some of the above financial submittals may not be applicable, and alternate requirements may be specified by SPP.

f. In the credit evaluation of Not-For-Profit Credit Customers, SPP may request additional information as part of the overall financial review process and will consider other relevant factors in determining financial strength and creditworthiness.

3.1.1.2 **References.** The Credit Customer must provide at least one bank reference.

3.1.1.3 **Loss Contingencies.** The Credit Customer must fully and accurately identify and describe each of the following, or state that there are no such matters applicable to the Credit Customer:

a. known pending or, to the Credit Customer's knowledge, threatened, court actions, arbitration proceeding, publicly

disclosed investigations, commitments, claims, contingencies, or existing or potential liabilities that are or would be Material if determined adversely to the Credit Customer;

b. prior bankruptcy declarations or petitions, voluntary or involuntary, by or against the Credit Customer, its predecessors, subsidiaries or Affiliates; and

c. Material defalcations or fraud by or involving the Credit Customer, its predecessors, subsidiaries or Affiliates, or any of their respective assets.

3.1.1.4 **Affiliates.** The Credit Customer must identify all Affiliates that are Credit Customers.

3.1.1.5 **Total Potential Exposure Information.** The Credit Customer shall provide an estimate of its current or anticipated transaction activity for all services under the Tariff or otherwise over the succeeding twelve (12) months sufficient to permit SPP to determine the Credit Customer's Total Potential Exposure.

3.1.1.6 **Attestation Minimum Criteria for Market Participation and of Risk Management Capabilities.** Each applying Market Participant shall submit to SPP a sworn, attested, or notarized statement signed by an authorized officer in the form attached as "Appendix E" to this Attachment H, attesting that:

a. The officer has signature authority to make the statement;
b. Employees or agents transacting in markets and services provided pursuant to the Tariff on behalf of the applying Market Participant have received, or will receive, applicable training with regard to their participation under this Tariff as a condition of being authorized to transact on behalf of the Market Participant;
c. The applying Market Participant will maintain current written risk management policies and procedures that address those risks that could materially affect the applying Market Participant's ability to pay its SPP invoices when due;

d. The applying Market Participant has available appropriate personnel resources, operating procedures, and technical abilities to promptly and effectively respond to SPP communications and directions related to, but not limited to, settlements, billing, credit requirements and other financial matters;

e. The applying Market Participant will maintain the minimum capitalization or alternate capitalization requirements set forth in Section 3.1.1.8 of this Attachment H; and

f. Certifying that the Market Participant meets the minimum criteria for market participation set forth in Section 3.1.1.8.

Such attestation shall be renewed and updated for each successive year of market participation, and shall be submitted to SPP no later than April 30 of each year.

The applying Market Participant shall be declined participation in Markets+ if: (i) the risk management capabilities of the applying Market Participant are deemed insufficient by SPP, (ii) SPP determines that the applying Market Participant does not meet the minimum criteria for market participation, (iii) the attestation is deemed insufficient by SPP to determine the risk management capabilities of the applying Market Participant, or (iv) the attestation is deemed insufficient by SPP to determine whether the applying Market Participant meets the minimum criteria for market participation. An applying Market Participant will have two (2) Business Days from receipt of notice from SPP that its attestation was deemed insufficient to cure any deficiency identified by SPP prior to being declined participation in Markets+.

3.1.1.7 Additional Information. At any time and from time to time, SPP may request such additional information as SPP determines is necessary and appropriate for the Credit Assessment and the Credit Customer shall timely provide such additional information. At any time, the Credit Customer may provide SPP with additional information that the Credit Customer considers relevant to the Credit Assessment.

3.1.1.8 Minimum Criteria for Market Participation.

3.1.1.8.1 Minimum Eligibility Requirements

In order to be eligible to transact in Markets+, each Market Participant must demonstrate to SPP that it qualifies as one of the following:

a. An "appropriate person," as defined under Section 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 6(c)(3)(A) through (J)). A Market Participant may qualify as an "appropriate person" by providing either: (i) an unlimited Corporate Guaranty in a form acceptable to SPP as described in Article 6 of this Attachment H and Appendix D of this Attachment H from an entity that demonstrates to SPP that it has in excess of $1 million of total net worth or in excess of $5 million of total assets per Market Participant for which that guarantor has issued an unlimited Corporate Guaranty, or (ii) an Irrevocable Letter of Credit or Surety Bond in an amount of $5 million or greater that the Market Participant acknowledges is separate from, and cannot be applied to meet, its credit requirements under this Attachment H.

b. An "eligible contract participant," as defined in Section 1a(18) of the Commodity Exchange Act (7 U.S.C. § 1a(18)) and in the Commodity Futures Trading Commission's regulation 1.3(m) (17 C.F.R. § 1.3(m))

c. A person or entity that is in the business of: (1) generating, transmitting or distributing electric energy or (2) providing electric services that are necessary to support the reliable operation of the transmission system (78 Fed. Reg. 19880, page 19914).

For purposes of meeting the minimum criteria for market participation under this Credit Policy, SPP shall accept annual audited Financial Statements prepared according to either United States

Generally Accepted Accounting Principles (US GAAP) or International Financial Reporting Standards (IFRS).

If a Market Participant is unable to meet the minimum eligibility requirements for market participation set forth in this Section 3.1.1.8.1, the Market Participant shall immediately notify SPP and immediately cease conducting transactions in Markets+. When SPP receives such notification from a Market Participant or determines that a Market Participant does not meet the minimum eligibility requirements set forth in this Section 3.1.1.8.1, SPP shall immediately terminate that Market Participant's transaction rights in Markets+.

In the event that a Market Participant is no longer able to demonstrate that it meets the minimum eligibility requirements set forth in this Section 3.1.1.8.1, and possesses, obtains, or has rights to possess or obtain any open or forward position in Markets+, SPP may take any action it deems necessary with respect to such open or forward positions. Such action may include but is not limited to, liquidation, transfer, assignment, or sale. The Market Participant will be entitled to any positive market value of such positions, net of any obligations due to SPP, notwithstanding its ineligibility to participate in Markets+. Nothing in this paragraph shall restrict SPP's ability to enforce SPP's rights to pursue and collect any amounts Market Participants may owe to SPP.

3.1.1.8.2 Minimum Capitalization Requirements

Each Market Participant that meets the minimum eligibility requirements in Section 3.1.1.8.1 shall also, at a minimum, possess one of the following:

a. A Tangible Net Worth of one million dollars ($1,000,000) as shown in the most recent fiscal year end audited financial statements as described in Section 3.1.1.1; or

b. Ten million dollars ($10,000,000) in assets as shown in the most recent fiscal year end audited financial statement as described in Section 3.1.1.1; or

c. A Credit Rating of, or equivalent to, BBB-; or

d. A Guaranty as described in Article Six of this Attachment H, and approved by SPP, through which the audited financials or Credit Rating of the Guarantor is used to meet at least one of the alternatives specified in (a) through (c) above; or

e. In the event a Market Participant cannot meet at least one of the alternatives specified in (a) through (d) above, the Market Participant shall, at a minimum, deposit with SPP two hundred thousand dollars ($200,000) in Financial Security to be segregated and unavailable to secure any market activity. Pursuant to election of this alternative, if the anticipated activity at time of application or actual market activity as determined in Article Five, of the Market Participant exceeds one hundred thousand dollars ($100,000) in Market Exposure, the Market Participant shall provide SPP twice the amount of Financial Security that would otherwise be required of the Market Participant pursuant to Section 4.4.

If the applying Market Participant is unable to meet the applicable minimum capitalization requirements in this Section 3.1.1.8.2, the applying Market Participant shall be declined participation in Markets+.

Failure at any time of a Market Participant to continue to satisfy these minimum capitalization requirements in this Section 3.1.1.8.2 shall be deemed a Material Adverse Change pursuant to Section 3.2.7.

3.1.1.9 Minimum Criteria and Risk Management Verification Process

Through a periodic compliance verification process, SPP shall review and verify Market Participants' eligibility for market participation based upon SPP's minimum criteria for market participation, risk management policies, practices, and procedures pertaining to the Market Participants' activities in Markets+. Such review shall include verification that:

1. The risk management framework is documented in a risk policy addressing market, credit, and liquidity risks;
2. The Market Participant maintains an organizational structure with clearly defined roles and responsibilities that clearly segregates trading and risk management functions;
3. There is clarity of authority specifying the types of transactions into which traders are allowed to enter;
4. The Market Participant has requirements that traders have adequate training or expertise relative to their authority in the systems and Markets+ in which they transact;
5. As appropriate, risk limits are in place to control risk exposures;
6. Reporting is in place to ensure that risks and exceptions are adequately communicated throughout the organization;
7. Processes are in place for qualified independent review of trading activities; and
8. As appropriate, there is periodic valuation or mark-to-market of risk positions.
9. The Market Participant meets the minimum participation criteria, including capitalization requirements, set forth in Section 3.1.1.8.

SPP may select Market Participants for review on a random basis and/or based on identified risk factors such as, but not limited to, the SPP markets in which the Market Participant is transacting, the magnitude of the Market Participant's transactions, or the volume of the Market Participant's open positions. Those Market Participants notified by SPP that they have been selected for review shall, upon fourteen (14) Calendar Days' notice, (or such longer time as SPP may agree) provide a copy of their current governing risk control policies, procedures, and controls applicable to their SPP market activities and shall also provide such further information or documentation pertaining to the Market Participants' activities in Markets+ as SPP requests. Market Participants selected for risk

management verification through a random process and satisfactorily verified by SPP shall be excluded from such verification process based on random selection for the subsequent two years. If the risk management verification yields results which SPP determines necessitates additional review, SPP shall maintain the right to review and the two-year exclusion shall not apply. SPP shall annually randomly select for review no more than twenty percent (20%) of the Market Participants.

Each selected Market Participant's continued eligibility to participate in Markets+ is conditioned upon SPP notifying the Market Participant of successful completion of SPP's verification. If SPP notifies the Market Participant in writing that it could not verify the Market Participant's continued eligibility to participate, SPP shall allow such Market Participant fourteen (14) Calendar Days to provide sufficient evidence for verification prior to declaring the Market Participant as ineligible to continue to participate in Markets+. The declaration of ineligibility shall be in writing with an explanation of why SPP could not complete the verification. If, prior to the expiration of such fourteen (14) Calendar Days (or longer period as SPP may provide), the Market Participant demonstrates to SPP that it has filed with FERC an appeal of SPP's risk management verification determination, then the Market Participant shall retain its transaction rights, pending FERC's determination on the Market Participant's appeal. SPP may retain outside expertise to perform the review and verification function described in this section. SPP and any third party it may retain will treat as confidential the documentation provided by a Market Participant under this section, consistent with the applicable provisions of the Tariff.

3.1.2 Rating Agency Information. In the initial Credit Assessment and in subsequent and ongoing assessments, SPP will consider Rating Agency reports applicable to the Credit Customer. This review will be focused on the Credit Customer's unsecured, senior long-term debt ratings. If these ratings are not available, SPP will consider issuer ratings.

3.1.3 Power Supply Agent Disclosure Requirements. A Not-For-Profit Credit Customer may request that its suggested Unsecured Credit Allowance calculation reflect as equity the outstanding balance of revenue bonds issued by the Not-For-Profit Credit Customer when such revenue bonds are issued solely in support of the Not-For-Profit Credit Customer's role as power supply agent for not-for-profit

electric distribution utilities. In support of such request, the Not-For-Profit Credit Customer must provide SPP with the following information:

(a) Management representation letter stating:

(i) Principal amount, in dollars, of revenue bonds outstanding;

(ii) Prior to default and after default, debt service on the revenue bonds is payable only after operating expenses are paid;

(iii) Amounts payable to SPP under this Tariff are operating expenses for purposes of the revenue bonds; and

(iv) The trustee for the revenue bonds has a valid and binding security interest in the revenues or net revenues from the power supply contracts to secure payment of the revenue bonds and the Not-For-Profit Customer has not granted any lien thereon prior to the lien of the bond resolution.

(b) Opinion of counsel stating:

(i) The power supply contracts are binding obligations of the Not-For-Profit Credit Customer enforceable in accordance with their terms;

(ii) The trustee of the revenue bonds has a valid and binding security interest in, or assignment and pledge of, the revenues or net revenues from the power supply contracts to secure payment of the revenue bonds;

(iii) The resolution or other document creating the security interest or pledge and providing for the priority of payment is enforceable in accordance with its terms;

(iv) Prior to default and after default, debt service on the revenue bonds is payable only after operating expenses are paid; and

(v) All amounts payable to SPP arising from transactions under this Tariff are operating expenses for purposes of the revenue bonds.

(c) All Rating Agency ratings on revenue bond(s).

The opinion of counsel referenced above shall be provided to SPP together with copies of the most recent written opinions of counsel, if any, for each member of the Not-For-Profit Credit Customer that relate to the enforceability of the power supply contract(s).

3.1.4 Guaranties. If the Credit Customer proposes a Guaranty to establish, contribute to, or maintain an Unsecured Credit Allowance, Credit Information required under Section 3.1.1 must be submitted with respect to both the Credit Customer and the proposed Guarantor.

3.2. Annual and Other Ongoing Credit Assessments.

3.2.1 Purpose of Annual and Other Ongoing Credit Assessments. At least once annually, SPP will review and update its Credit Assessment for each Credit Customer. This will include a review of the Credit Customer's creditworthiness and consideration of revisions of the Credit Customer's (a) Unsecured Credit Allowance; (b) Financial Security requirements; and (c) Total Credit Limit. In its sole discretion, SPP may conduct additional reviews and updates, including reviews in response to new facts or occurrences that may bear upon the Credit Customer's creditworthiness. Unless otherwise stated, all annual information required under Section 3.2 shall be provided to SPP no later than 120 Calendar Days after the end of the Credit Customer's fiscal year, or such later date as SPP may agree.

3.2.2 Procedures for Posting Additional Financial Security or Taking Other Corrective Measures. In the event a Credit Customer experiences a Material Adverse Change, SPP may invoke its right to require the Credit Customer to post additional Financial Security, cease one or more transactions, or take other measures to restore confidence in the Credit Customer's ability to transact safely. In addition, based upon the annual or other Credit Assessment, SPP may, at any time, revise any (a) Unsecured Credit Allowance; (b) Financial Security requirements; and (c) Total Credit Limit, applicable to the Credit Customer. If SPP has upwardly revised the required amount of Financial Security, the Credit Customer will have two (2) Business Days from receipt of the notice from SPP to provide the required Financial Security, in an amount and form acceptable to SPP. Failure to provide additional required Financial Security shall be a Default under this Credit Policy and a default under the Tariff.

3.2.3 Rating Agency Information. The Credit Customer will give notice to SPP of any changes to its Credit Ratings within five (5) Business Days of the announcement of the change.

3.2.4 Financial Statements. On an annual basis, and except as otherwise stated with respect to quarterly reports, each Credit Customer must provide SPP with updated Financial Statements within ten (10) Business Days after they become available, and in no event later than 120 Calendar Days after the end of the Credit Customer's fiscal year, or such later date as SPP may agree Quarterly reports must be provided quarterly, within ten (10) Business Days after they become available., unless Credit Customer does not produce quarterly financial statements Financial Statements may be submitted in the manner provided under Section 3.1.1.1.

3.2.5 Power Supply Agent Disclosure Requirements. A Not-For-Profit Credit Customer that initially qualified to have its suggested Unsecured Credit Allowance calculation reflect as equity the outstanding balance of revenue bonds issued by the Not-For-Profit Credit Customer, and is requesting to continue to have its suggested Unsecured Credit Allowance calculation reflect as equity the outstanding balance of revenue bonds issued by the Not-For-Profit Credit Customer when such revenue bonds are issued solely in support of the Not-For-Profit Credit Customer's role as power supply agent for not-for-profit electric distribution utilities, must at all times comply with the following information reporting requirements:

(a) The Not-For-Profit Credit Customer must advise SPP of the principal amount of revenue bonds outstanding on an annual basis;

(b) The Not-For-Profit Credit Customer must advise SPP within ten (10) Business Days if the principal amount of the revenue bonds outstanding is reduced by more than twenty percent (20%) from the amount last certified by the Not-For-Profit Credit Customer;

(c) The Not-For-Profit Credit Customer must advise SPP immediately if the security interest of the trustee is released or the Not-For-Profit Credit Customer grants any lien prior to the lien of the bond resolution; and

(d) The Not-For-Profit Credit Customer must advise SPP within ten (10) Business Days of any downgrade of any of the Not-For-Profit Credit Customer's revenue bond ratings issued by a Rating Agency.

3.2.6 Other Credit Information. On an annual basis, each Credit Customer must provide SPP with the information specified in Section 3.1.1.3 (Loss Contingencies), 3.1.1.4 (Affiliates), 3.1.1.6 (Additional Information).

3.2.7 Material Adverse Changes. Each Credit Customer must give SPP notice of any Material Adverse Change in its financial condition (and, as applicable, the financial condition of its Guarantor) within two (2) Business Days of the occurrence of the Material Adverse Change. If a Credit Customer or Guarantor files a Form 10-K, Form 10-Q, or Form 8-K with the SEC, notice of such filing, timely delivered to SPP in accordance herewith, will suffice on the condition that such notice states that the filing addresses a Material Adverse Change.

A Material Adverse Change in financial condition includes any Material change in operations or financial condition that a reasonable examiner of creditworthiness would deem material to decisions concerning the extension of credit, including but not limited to, any of the following ("Material Adverse Change"):

a. A downgrade of any debt rating or issuer rating, or change in the outlook of any Credit Rating, including debt rating or issuer rating;

b. Any placement on a credit watch with negative implication by a Rating Agency;

c. The filing of a lawsuit or initiation of an arbitration, publicly disclosed investigation or other proceeding (including regulatory proceeding) which if decided adversely could have a Material effect on any current or future financial results or financial condition;

d. The merger, acquisition or any other form of business combination involving the credit customer.

e. Any adverse changes in financial condition which, individually, or in the aggregate, are Material;

f. Any adverse changes, events or occurrences which, individually or in the aggregate, could affect the ability of the Credit Customer to pay its debts as they become due or could have a Material adverse effect on any current or future financial results or financial condition;

g. Discovery or disclosure of conflict of interest issues;

h. Resignation or removal of a key officer or director;

i. Any action requiring the filing of a Form 8-K;

j. Any report of a quarterly or annual loss or a decline in earnings of ten (10) percent or greater compared to the prior period;

k. Any restatement of prior financial statements; and

l. Failure of a Market Participant to continue to satisfy the minimum capitalization criteria for market participation specified in Section 3.1.1.8.2.

3.2.7.1 Notification of a Material Adverse Change by SPP to a Credit Customer. Upon the occurrence of a Material Adverse Change and prior to SPP compelling a Credit Customer to post additional Financial Security, cease one or more transactions, or take other measures to restore confidence in the Credit Customer's ability to transact business safely as a result of any Material Adverse Change, SPP shall provide, when feasible, reasonable advance notice in writing, by electronic mail, hand delivery, reputable overnight courier, or first-class mail, to the Credit Contact designated by the Credit Customer pursuant to Section 9.1 of this Credit Policy. If delivery to the Credit Contact fails, then SPP may effect delivery to any officer, executive, or manager of the Credit Customer. Such notice shall identify the reasoning behind the invocation of the Material Adverse Change clause and be signed by an authorized representative of SPP.

3.2.8 Affiliates. Each Credit Customer must identify all Affiliates that are Credit Customers.

3.2.9 Additional Information. At any time and from time to time, SPP may request such additional information as SPP reasonably determines is necessary and appropriate for the Credit Assessment and the Credit Customer shall timely provide such additional information. At any time, the Credit Customer may provide SPP with additional information that the Credit Customer considers relevant to the Credit Assessment.

3.2.10 Guaranties. If the Credit Customer relies upon a Guaranty to maintain an Unsecured Credit Allowance, Credit Information required under Section 3.2 must be submitted with respect to both the Credit Customer and the Guarantor.

3.2.11 Alternate Requirements. For Not-For-Profit Credit Customers, some of the above financial submittals may not be applicable, and alternate requirements may be specified by SPP.

3.2.12 In the credit evaluation of Not-For-Profit Credit Customers, SPP may request additional information as part of the overall financial review process and will consider other relevant factors in determining financial strength and creditworthiness.

3.3 SPP Rights to Use Other Information. Notwithstanding any provision of this Credit Policy, SPP shall have the right to utilize, in a Credit Assessment, any information of which it is aware concerning the Credit Customer.

3.3.1 Consistent with the Commission's Order No. 895 and notwithstanding any provision in the Tariff to the contrary, SPP is permitted to (a) share credit-related information of Credit Customers, applicants seeking to become Credit Customers, and their respective Affiliates with Commission-jurisdictional regional transmission organizations and independent system operators for the purpose of credit risk management and mitigation and (b) use credit-related information received from Commission-jurisdictional regional transmission organizations and independent system operators to the same extent and for the same purposes that SPP may use credit-related information received directly from Credit Customers, applicants seeking to become Credit Customers, and their respective Affiliates. SPP will treat credit-related information it receives under this provision in the same manner that SPP treats Confidential Information to the extent such treatment does not conflict with the Commission's requirements in Order No. 895 and this provision.

3.4 Positive Material Change in Financial Condition of the Credit Customer. If there is a positive Material change in the financial condition of the Credit Customer, a significant reduction in the Total Potential Exposure of the Credit Customer, or any other change that the Credit Customer believes may warrant an increase in the Credit Customer's Unsecured Credit Allowance and/or a reduction in the Financial Security required of the Credit Customer, the Credit Customer may make a written request to SPP to update the Credit Assessment and include or refer to any supporting information. SPP may request any Credit Information described in Section 3.2 to evaluate the merit of the Credit Customer's request. SPP anticipates that it will respond to the Credit Customer's request within a reasonable period of time, generally within ten (10) Business Days after receiving all

information that is required for an ongoing review as required in this Article.

ARTICLE FOUR

Creditworthiness and Total Credit Limit

4.1 Creditworthiness Overview. SPP will establish a Total Potential Exposure for each Credit Customer based on the Credit Customer's estimated cumulative financial obligation arising under the Tariff or otherwise to SPP as provided in Article 5. The Total Potential Exposure is the amount that the Credit Customer must support with credit. The credit will consist of a combination of the Unsecured Credit Allowance and Financial Security, or either of them. SPP will determine the Credit Customer's Unsecured Credit Allowance based upon the Composite Credit Score. The Composite Credit Score, as defined herein, is a determination of financial strength and creditworthiness, based upon the Credit Assessment. Where Credit Customers are Affiliates of each other, an aggregate Unsecured Credit Allowance will be established for the Affiliates, as provided below. If the Credit Customer's Unsecured Credit Allowance is less than its Total Potential Exposure, the Credit Customer will be required either to establish additional credit in the amount of the difference by posting Financial Security or to decrease its Total Potential Exposure. A Credit Customer's total credit with SPP under the Markets+ Tariff, consisting of the Unsecured Credit Allowance and any Financial Security, is the Credit Customer's Total Credit Limit. A Credit Customer may provide additional Financial Security at any time to increase or maintain its Total Credit Limit, for example, in order to increase its Total Potential Exposure or to compensate for a reduction in its Unsecured Credit Allowance.

4.2 Composite Credit Score. The "Composite Credit Score" is the numerical result of SPP's scoring process based upon various quantitative and qualitative predictors of creditworthiness as set forth in this Section. The results are scaled from one (1) to six (6) with one (1) being the strongest score and six (6) being the weakest. Key factors in the scoring process include financial ratios, years in business, and Credit Ratings. SPP will apply all measures used to determine Composite Credit Scores in a consistent manner. The respective models SPP will use to determine the Composite Credit Score for Large Company Credit Customers, Small Company Credit Customers, and Not-For-Profit Credit Customers are set forth in this Section.

4.2.1 Large Company Credit Scoring. The Large Company Credit Customer model will be utilized for Credit Customers with net fixed assets equal to or in excess of $250 million ("Large Company Credit Customers" or "Large Company"). The Large Company Credit Score will be comprised of a Quantitative Score and a Qualitative Score. Each score is then weighted as shown below to build a Composite Credit Score.

Large Company Analysis	Weight
Quantitative Score	70%
Qualitative Score	30%

4.2.1.1 **Quantitative Score.** The Quantitative Score is based on the financial ratios below. These measures will be calculated for each Large-Company Credit Customer and compared with benchmarks to assign a score of one (1) to six (6) for each measure. A score of one (1) indicates that the Credit Customer has a strong financial health with regard to the measure, while a score of six (6) indicates poor financial health with regard to the measure. The following measures are used:

a. Current Ratio—Current Assets/Current Liabilities

b. EBIT Interest Coverage—(Interest Expense + Income Taxes + Net Income) / Interest Expense

c. Total Debt to Total Capitalization ("TD/TC")—(Long Term Debt + Current Portion + Other Short Term Borrowings) / (Total Debt + Preferred Equity + Common Equity)

d. Funds from Operations ("FFO") to Total Debt—(Cash from Operating Activities - Changes in Operating Assets and Liabilities) / (Long Term Debt + Current Portion + Other Short Term Borrowings)

The measures are then assessed as follows to calculate the total Quantitative Score:

Scale	Current	EBIT Interest	TD/TC	FFO to Total Debt
1	>1.34	>4.99	<.30	>.350
2	1.15 – 1.34	3.50 – 4.99	.30 - .39	.271 - .350
3	1.00 – 1.14	2.50 – 3.49	.40 - .49	.181 - .270
4	0.85 – 0.99	2.00 – 2.49	.50 - .59	.120 - .180
5	0.70 – 0.84	1.25 – 1.99	.60 - .69	.070 - .119
6	<0.70	<1.25	>.69	<.070

The measures are weighted as follows:

Large Company Financial Ratios	Weight
Current Ratio	10%
EBIT Interest Coverage	25%

Total Debt to Total Capitalization	25%
FFO to Total Debt	40%
	100%

If one or more ratios cannot be calculated due to insufficient data to calculate the ratio, the weight that would have been assigned to that ratio or ratios will be allocated equally among the remaining ratios.

4.2.1.2 **Qualitative Score.** The Qualitative Score, also on a scale of one (1) to six (6), will assess non-financial measure information about a Credit Customer's creditworthiness. A score of one (1) indicates that the Credit Customer has strong qualitative measures, while a score of six (6) indicates poor qualitative measures. The qualitative analysis will take into account a variety of information, but at a minimum will include the assessment of the following characteristics:

-Management
-Regional / Commodity Diversity
-Physical Liquidity
-Financial Liquidity
-Quality of Equity
-Volatility of Earnings
-Regulation/Rates
-Senior Unsecured Debt Rating
-SPP Payment Record
-Risk Procedures

4.2.1.3 **Composite Credit Score.** The Composite Credit Score is the weighted average of the Quantitative Score and the Qualitative Score. To illustrate, assume the following:

Large Company Qualitative Score = 4.0

Large Company Financial Measures:

	Value	**Score**	**Weight**
Current Ratio	.82	5	10%
EBIT Interest Coverage	2.08	4	25%
Total Debt to Total Capitalization	.63	5	25%
FFO to Total Debt	.17	4	40%

Large Company Quantitative Score =

(5 x 10%) + (4 x 25%) + (5 x 25%) + (4 x 40%) = 4.35

Large Company Credit Score = (4.35 x 70%) + (4 x 30%) = 4.25

4.2.2 Small Company Credit Scoring. The Small Company model will be utilized for Credit Customers with net fixed assets less than $250 million ("Small Company Credit Customers" or "Small Company"). The Small Company Composite Credit Score will be comprised of a Quantitative Score and a Qualitative Score. Each score is then weighted as shown below to build a Composite Credit Score.

Small Company Analysis	**Weight**
Quantitative Score	70%
Qualitative Score	30%

4.2.2.1 Quantitative Score. The Quantitative Score is based on the financial ratios below. These measures will be calculated for each Small Company Credit Customer and compared with benchmarks to assign a score of one (1) to six (6) for each measure. A score of one (1) indicates that the Credit Customer has a strong financial health with regard to the measure, while a score of six (6) indicates poor financial health with regard to the measure. The following measures are used:

a. Current Ratio—Current Assets/Current Liabilities

b. EBIT Interest Coverage—(Interest Expense + Income Taxes + Net Income) / Interest Expense

c. Total Liabilities to Total Net Worth ("TL/TNW")—(Total Liabilities) / (Total Equity-Intangibles-Treasury Stock)

d. Funds from Operations ("FFO") to Total Debt—(Cash from Operating Activities - Changes in Operating Assets and Liabilities) / (Long Term Debt + Current Portion + Other Short Term Borrowings)

e. Return on Assets ("ROA")—Net Income / Total Assets

The values are then assessed as follows to calculate the total Quantitative Score:

Scale	**Current**	**EBIT Interest**	**TL/TNW**	**FFO to Total Debt**	**ROA**
1	>2.50	>4.99	<0.40	>.350	>.120
2	1.75 – 2.50	3.50 – 4.99	0.40 - 0.70	.271-.350	.100 - .120

3	1.40 – 1.74	2.50 – 3.49	0.71 – 1.49	.181 - .270	.075 - .099
4	1.15 – 1.39	2.00 – 2.49	1.50 – 2.25	.120 - .18	.045 - .074
5	1.00 – 1.14	1.25 – 1.99	2.26 – 4.00	.070 - .119	.015 - .044
6	<1.00	<1.25	>4.00	<.070	<.015

The measures are weighted as follows:

Small Company Financial Ratios	**Weight**
Current Ratio	25%
EBIT Interest Coverage	10%
Total Liabilities / Total Net Worth	25%
FFO to Total Debt	15%
ROA	25%
	100%

If one or more ratios cannot be calculated due to insufficient data to calculate the ratio, the weight that would have been assigned to that ratio or ratios will be allocated equally among the remaining ratios.

4.2.2.2 **Qualitative Score.** The Qualitative Score, also on a scale of one (1) to six (6), will assess non-financial measure information about a Credit Customer's creditworthiness. A score of one (1) indicates that the Credit Customer has strong qualitative measures, while a score of six (6) indicates poor qualitative measures. The qualitative analysis will take into account a variety of information, but at a minimum will include the assessment of the following characteristics:

-Management
-Regional / Commodity Diversity
-Physical Liquidity
-Financial Liquidity
-Quality of Equity
-Volatility of Earnings
-Regulation/Rates
-Peer Comparison using SIC codes
-Senior Unsecured Debt Rating
-SPP Payment Record

4.2.2.3 **Composite Credit Score.** The Composite Credit Score is the weighted average of the Quantitative Score and the Qualitative Score. To illustrate, assume the following:

Small Company Qualitative Score = 4

Small Company Financial Measures:

	Value	Score	Weight
Current Ratio	1.10	5	25%
EBIT Interest Coverage	1855.00	1	10%
Total Liabilities / Total Net Worth	2.47	5	25%
FFO to Total Debt	0.03	6	15%
ROA	0.02	5	25%

Small Company Quantitative Score =
(5 x 25%) + (1 x 10%) + (5 x 25%) + (6 x 15%) + (5 x 25%) = 4.75

Small Company Credit Score =
(4.75 x 70%) + (4 x 30%) = 4.53

4.2.3 Not-For-Profit Credit Scoring. The Not-For-Profit model will be utilized for Credit Customers who are not structured to generate profits for investors ("Not-For-Profit Credit Customers" or "Not-For-Profit"), including electric cooperatives, municipalities, and government agencies. The Not-For-Profit Composite Credit Score will be comprised of a Quantitative Score and a Qualitative Score. The lower of the Composite Credit Score calculated using two alternative weights for the Quantitative Score and the Qualitative Score as shown below shall be used in determining the allocation of the Not-For-Profit Credit Customer's Unsecured Credit Allowance.

Not For Profit Credit Customer Analysis	Weight	
	Alternative 1	Alternative 2
Quantitative Score	40%	50%
Qualitative Score	60%	50%

4.2.3.1 Quantitative Score. The Quantitative Score is based on the financial ratios below. These measures will be calculated for each Not-For-Profit Credit Customer and compared with benchmarks to assign a score of one (1) to six (6) for each measure. A score of one (1) indicates that the Credit Customer has a strong financial health with regard to the measure, while a score of six (6) indicates poor financial health with regard to the measure. The following measures, or their substantive equivalents for not-for-profit entities, are used:

a. Current Ratio ("CR")—Current Assets / Current Liabilities

b. Debt Service Coverage ("DSC")—(Operating Income + Interest Expense + Depreciation + Interest Income + Cash Portion of Capital Credits - Onetime Charges)/(Interest Expense + Debt Amortization)

c. Times Interest Earned Ratio ("TIER")—(Interest Expense + Patronage Capital or Margins or Changes in Net Assets) / (Interest Expense)

d. Total Debt to Total Capitalization ("TD/TC")—(Long Term Debt + Current Portion + Other Short Term Borrowings) / (Total Debt + Preferred Equity + Common Equity). Members' Equity could also be called Net Assets or Patronage Capital.

The values are then assessed as follows to calculate the total Quantitative Score:

Not-For-Profit Credit Customer Model Ratio Scales

Scale	**CR**	**DSC**	**TIER**	**TD/TC**
1	>1.34	>1.99	>2.00	<.50
2	1.15 – 1.34	1.50 – 1.99	1.50 – 2.00	.51 - .74
3	1.00 – 1.14	1.00 – 1.49	1.00 – 1.49	.75 - .85
4	0.85 – 0.99	0.80 – 0.99	0.80 – 0.99	.86 - .93
5	0.70 – 0.84	0.60 – 0.79	0.50 – 0.79	.94 - .99
6	<0.70	<0.60	<0.50	>.99

The measures are weighted as follows:

Not-For-Profit Credit Customer Financial Ratios	**Weight**
Current Ratio	15%
Debt Service Coverage	35%
Times Interest Earned Ratio	20%
Total Debt / Total Capitalization	30%
	100%

If one or more ratios cannot be calculated due to insufficient data to calculate the ratio, the weight that would have been assigned to that ratio or ratios will be allocated equally among the remaining ratios.

4.2.3.2 **Qualitative Score.** The Qualitative Score, also on a scale of one (1) to six (6), will assess non-financial measure information about a Credit Customer's creditworthiness. A score of one (1) indicates that the Credit Customer has strong qualitative measures, while a score of six (6) indicates poor qualitative measures. The qualitative analysis will take into account a variety of information, but at a minimum will include the assessment of the following characteristics:

-Regulation/Rates
-Terms of wholesale power contracts
-Customer count served
-Power supply portfolio (e.g., contracts, assets, etc)
-Management
-Ability to access short-term capital
-Senior Unsecured Debt Rating
-SPP Payment Record

4.2.3.3 **Composite Credit Score**. The Composite Credit Score is the weighted average of the Quantitative Score and the Qualitative Score. To illustrate, assume the following:
Not-For-Profit Qualitative Score = 2

Not-For-Profit Financial Measures:

	Value	Score	Weight
Current Ratio	1.42	1	15%
Debt Service Coverage	1.17	3	35%
Times Interest Earned Ratio	0.73	5	20%
Total Debt / Total Capitalization	1.50	6	30%

Not-For-Profit Quantitative Score =
(1 x 15%) + (3 x 35%) + (5 x 20%) + (6 x 30%) = 4.00

Not-For-Profit Credit Score =
(4.00 x 40%) + (2.0 x 60%) = 2.80 using Alternative 1, or;

(4.00 x 50%) + (2.0 x 50%) = 3.00 using Alternative 2.

The lower Composite Credit Score resulting from utilizing the two alternatives is 2.80, so it will be the Composite Credit Score used in allocating this Not-For-Profit Credit Customer's Unsecured Credit Allowance as described in Section 4.3 below.

4.3 Unsecured Credit Allowance.

The Composite Credit Score is converted into an "Unsecured Credit Allowance," which is a percentage of Tangible Net Worth. (Tangible Net Worth = Total Equity – Intangibles – Treasury Stock). The Composite Credit Score is a numeric value on a scale of one (1) to six (6) with one (1) indicating stronger creditworthiness and six (6) indicating weaker creditworthiness. The conversion into an Unsecured Credit Allowance is based on the percentage values stated in Table 1.

Table 1

Composite Credit Score	% Tangible Net Worth Small Company Model	% Tangible Net Worth Large Company Model	% Tangible Net Worth Not For Profit Model
1.00 - 1.99	5.00%	5.00%	7.500%
2.00 - 2.99	3.00%	3.00%	4.500%
3.00 - 3.59	2.00%	2.00%	3.000%
3.60 - 4.39	0.75%	0.75%	1.125%
4.40 - 4.99	0.25%	0.25%	0.375%
5.00 - 6.00	0%	0%	0.000%

To illustrate, a Large Company Credit Customer with a Composite Credit Score of 4.36 and Tangible Net Worth of $501,468,000 would have a suggested Unsecured Credit Allowance calculated as follows:

Unsecured Credit Allowance = Table 1 Percentage x Tangible Net Worth

= 0.75% x $501,468,000

= $3,761,010

4.3.1 Revenue Bond Adjustment to Tangible Net Worth Value for Power Supply Agents. For Not-For-Profit Credit Customers that issue revenue bonds solely in support of their role as power supply agent for not-for-profit electric distribution utilities and meet: (a) the disclosure requirements in: (i) Section 3.1.3 of this Credit Policy and (ii) Section 3.2.5 of this Credit Policy; and (b) have a revenue bond rating or revenue bond ratings equal to or better than Baa1 issued by Moody's or BBB+ issued by S&P, the calculation of the suggested Unsecured Credit Allowance shall be based on an adjusted value for Tangible Net Worth. The adjusted value for Tangible Net Worth shall include the outstanding balance of revenue bonds as of the date of the calculation.

To illustrate, if the Not-For-Profit Credit Customer met all of the disclosure requirements for power supply agents, had a Tangible Net Worth of $2,000,000,

and had $8,000,000 principal amount of revenue bonds outstanding, the adjusted Tangible Net Worth to be used in computing the suggested Unsecured Credit Allowance would be $10,000,000 (the sum of the adjusted Tangible Net Worth and the principal amount of revenue bonds outstanding as of the date of the calculation).

4.3.2 Maximum and Minimum Unsecured Credit Allowances. Notwithstanding the calculation under Section 4.3:

4.3.2.1 No Credit Customer shall have an Unsecured Credit Allowance in excess of $50 million; and

4.3.2.2 On the condition that a Not-For-Profit provides all required Credit Information and executes all documents required under this Credit Policy, and subject to the Default provisions of this Credit Policy, a Not-For-Profit Credit Customer shall have a minimum Unsecured Credit Allowance in the amount of $250 thousand.

4.3.3 Guaranty. In the event that the Credit Customer has a Guaranty, the Unsecured Credit Allowance will be based on the Credit Assessments of the Credit Customer and the Guarantor.

4.3.4 Unsecured Credit Allowance for Affiliates.

4.3.4.1 **Determination of Creditworthiness of Combined Affiliates.** If two or more Credit Customers are Affiliates, and each is granted an Unsecured Credit Allowance and a corresponding Total Credit Limit, SPP will consider the overall creditworthiness of the Affiliated Credit Customers when determining the Unsecured Credit Allowances in order not to grant more unsecured credit than the overall group of affiliated entities could support. SPP will work with Affiliated Credit Customers to allocate the total Unsecured Credit Allowance among the Affiliates while assuring that no individual Credit Customer, nor common guarantor, exceeds the Unsecured Credit Allowance appropriate for its credit strength. A $50 million maximum Unsecured Credit Allowance shall apply to all Affiliates as though the Affiliates are a single Credit Customer.

Example: Credit Customers A and B each have a $10.0 million Guaranty from their common parent, a holding company with an Unsecured Credit Allowance calculation of $12.0 million. SPP may limit the Unsecured Credit Allowance for each Credit Customer to $6.0 million, so the total Unsecured Credit Allowance does not exceed the corporate total of $12.0 million.

4.3.4.2 **Guaranty.** If the Guaranty is applicable to Affiliates (i.e., more than one Credit Customer), then the Unsecured Credit Allowance of the Guarantor shall be allocated among such Affiliates and the applicable allocation shall be utilized in determining each Affiliated Credit Customer's Unsecured Credit Allowance.

4.3.5 Continuous Right to Modify. SPP has the right at any time to modify any Unsecured Credit Allowance and/or require additional Financial Security as may be reasonably necessary to support the Credit Customer's ability to pay for any market services SPP may provide. If the modification results in a reduction or revocation of Unsecured Credit Allowance and the reduction or revocation results in the need to provide Financial Security, then the rights and duties of SPP and the Credit Customer shall be as set forth in Section 3.2.2.

4.4 Financial Security Requirement. If a Credit Customer (i) is denied an Unsecured Credit Allowance, or (ii) is granted an Unsecured Credit Allowance that is below its Total Potential Exposure calculated pursuant to Article 5, then the Credit Customer may submit Financial Security to cover or exceed the difference in the amount of the Unsecured Credit Allowance granted to the Credit Customer and the amount of its Total Potential Exposure. A Credit Customer electing to satisfy the alternative criteria for market participation specified in Section 3.1.1.8.2(e) and whose anticipated or actual market activity, as determined in Article Five, exceeds One Hundred Thousand Dollars ($100,000) in Market Exposure shall provide Financial Security that is twice the amount calculated to satisfy its Financial Security Requirement pursuant to this Section 4.4. Any Credit Customer may provide Financial Security in lieu of or in addition to the Unsecured Credit Allowance it was granted. Upon the Credit Customer's request, SPP shall provide a written explanation of how it determined the amount of required Financial Security for that Credit Customer.

4.5 Total Credit Limit. The "Total Credit Limit" is the amount of any Unsecured Credit Allowance approved by SPP for the Credit Customer, plus the amount of any Financial Security the Credit Customer has provided to SPP. SPP shall determine the Total Credit Limit for each Credit Customer. Upon the Credit Customer's request, SPP shall provide a written explanation of how it determined the Unsecured Credit Allowance and the amount of required Financial Security for that Credit Customer. SPP will respond to the Credit Customer's request within five (5) Business Days.

ARTICLE FOUR A

Virtual Energy Bids and Virtual Energy Offers

4A.1 Overview.

4A.1.1 Virtual Energy Bids and Virtual Energy Offers create potential exposure of non-payment, and therefore, have a credit requirement. SPP does not require the Credit Customer to segregate, allocate, or reserve a portion of its Total Credit Limit to support its Virtual Energy Bids and Virtual Energy Offers in the Day-Ahead Market. However, SPP analyzes the Credit Customer's Virtual Energy Bids and Virtual Energy Offers to determine if the Credit Customer has credit available to support its Virtual Energy Bids and Virtual Energy Offers at the time the Bids or Offers are submitted. Only the Virtual Energy Bids and Virtual Energy Offers that the Credit Customer has credit available to support will be credit approved for the Day-Ahead Market.

4A.1.2 In its analysis, SPP will calculate the Estimated Virtual Exposure ("EVE") based on the Credit Customer's Virtual Energy Bids and Virtual Energy Offers. Using the EVE, SPP will determine if the Credit Customer has available credit to support its Virtual Energy Bids and Virtual Energy Offers. After the close of the Day-Ahead Market for an Operating Day, the credit requirement associated with the Credit Customer's cleared Virtual Energy Bids and Virtual Energy Offers will be adjusted to reflect the actual megawatts that cleared.

4A.1.3 The total EVE for a Credit Customer includes both (i) the calculation of EVE for Virtual Energy Bids and Virtual Energy Offers prior to the close of the Day-Ahead Market; and (ii) the EVE calculations post Day-Ahead Market clearing updated to reflect the actual cleared Virtual Energy Bids and Virtual Energy Offers.

4A.1.4 This Article addresses the calculation of the EVE and the credit requirements associated with the submission of Virtual Energy Bids and Virtual Energy Offers in the Day-Ahead Market and the Virtual Energy Bids and Virtual Energy Offers that clear in the Day-Ahead Market.

4A.2 Calculation of Estimated Virtual Exposure (EVE) Prior to the Close of the Day-Ahead Market for an Operating Day. When a Virtual Energy Bid or Virtual Energy Offer is submitted, SPP will calculate the EVE using reference prices for the Virtual Energy Bid or Virtual Energy Offer and the maximum megawatts submitted. If multiple Virtual Energy Bids and Virtual Energy Offers are submitted in a single submission, the EVE will be calculated for the single submission as a whole. If a Virtual Energy Bid or Virtual Energy Offer contains multiple hours, all of the hours will be included in the EVE calculation. The EVE is calculated for the submittal of Virtual Energy Bids and Virtual Energy Offers. In the event that both a Virtual Energy Bid and Virtual Energy Offer are

submitted in the same submission for the same node and same operating hour, the one with the higher dollar value will be used in the EVE calculation for that submission.

4A.2.1 For a given Virtual Energy Bid the Virtual Energy Bid EVE is the sum of (i) the product of the Virtual Energy Bid reference price for the Settlement Location of the Virtual Energy Bid times the maximum megawatt value of the submitted Bid curve plus (ii) the virtual transaction fee. For a given Virtual Energy Offer the Virtual Energy Offer EVE is the sum of (i) the product of the Virtual Energy Offer reference price for the Settlement Location of the Virtual Energy Offer times the maximum megawatt value of the submitted Offer curve plus (ii) the virtual transaction fee.

4A.2.1.1 If a Market Participant submits both a Virtual Energy Bid and a Virtual Energy Offer at the same location for the same hour, only the Virtual Energy Bid or Virtual Energy Offer with the greater EVE is included in the calculation of the EVE for the submission.

4A.2.1.2 The EVE for a single submission of Virtual Energy Bids and Virtual Energy Offers is equal to the sum of the hourly Virtual Energy Bid EVEs for each Virtual Energy Bid in the submission and the sum of the hourly Virtual Energy Offer EVEs in the submission, with the adjustment described in 4A.2.1.1 if both a Virtual Energy Bid and Virtual Energy Offer are received for the same location and hour. If Credit Customer cancels a Virtual Energy Bid or Virtual Energy Offer prior to the close of the Day-Ahead Market for the Operating Day for which it is submitted, the EVE associated with the canceled portion of the submission is removed from the calculation of the EVE for the submission.

4A.2.1.3 The Virtual Energy Bid reference price is based on the difference between the Day-Ahead Locational Marginal Prices and the Real-Time Locational Marginal Prices in the prior year, at each node. The Virtual Energy Bid reference price for a given day is the 97th percentile hourly difference from the same quarter in the previous year. For virtual transactions occurring in the first quarter of 2022, the calculation of the Virtual Energy Bid reference price will not include the hourly differences from the operating hours in February 12, 2021 through February 19, 2021.

4A.2.1.4 The Virtual Energy Offer reference price is based on the difference between the Real-Time Locational Marginal Price and the Day-Ahead Locational Marginal Price in the prior year, at each node. The Virtual Energy Offer reference price for a given day is the 97th

percentile hourly difference from the same quarter in the previous year. For virtual transactions occurring in the first quarter of 2022, the calculation of the Virtual Energy Offer reference price will not include the hourly differences from the operating hours in February 12, 2021 through February 19, 2021.

4A.2.1.5 Calculation of Virtual Energy Bid and Virtual Energy Offer Reference Prices During the Initial Six-Months of the Virtual Market in Markets +. During the initial six-months of the virtual market within Markets +, prior to the accumulation of complete Real-Time and Day-Ahead Locational Marginal Price data sufficient to calculate the Virtual Energy Bid and Virtual Energy Offer references prices pursuant to sections 4A.2.1.3 and 4A.2.1.4, SPP shall use data representative of the expected Day-Ahead and Real-Time Market results based on the Real-Time and Day-Ahead Locational Marginal Prices settled during the initial five-months of Markets + operations or other available information.

4A.2.1.6 Calculation of Virtual Energy Bid and Virtual Energy Offer Reference Prices for New Settlement Locations. When a new Settlement Location is created and until actual Virtual Energy Bid and Virtual Energy Offer reference prices can be calculated pursuant to section 4A.2.1.3 and 4A.2.1.4 for that Settlement Location, SPP will use the system average virtual reference price. The system average virtual reference price for a given quarter is the mean of all of the Virtual Energy Bid and Virtual Energy Offer reference prices for that quarter.

4A.3 Determination of Credit Approved Virtual Energy Bids and Virtual Energy Offers.

4A.3.1 If the EVE for a submission of Virtual Energy Bids and Virtual Energy Offers is less than the Credit Customer's available credit, which is equal to the Credit Customer's Total Credit Limit less its Total Potential Exposure, then the submission is credit approved. Credit approved Virtual Energy Bids and Virtual Energy Offers, unless withdrawn will be included in the Day-Ahead Market.

4A.3.2 If the EVE for a submission of Virtual Energy Bids and Virtual Energy Offers is greater than the Credit Customer's available credit, which is equal to the Credit Customer's Total Credit Limit less its Total Potential Exposure, then the submission will be rejected. Rejected Virtual Energy Bids and Virtual Energy Offers will not be included in the Day-Ahead Market and will not affect the Total Potential Exposure calculation.

4A.3.3 Modifications to Virtual Energy Bids and Virtual Energy Offers prior to the close of the Day-Ahead Market for the Operating Day for which they were submitted will be evaluated using the same procedures. Modifications are evaluated based on their net credit impact. The EVE for the modified Virtual Energy Bids and Virtual Energy Offers submission will be revised to incorporate the modifications to the submission.

4A.3.3 The EVE for credit approved Virtual Energy Bids and Virtual Energy Offers submissions that have not yet settled or cleared in the Day-Ahead Market is included in the Total Potential Exposure calculation as set forth in Article 5. Therefore, the determination of whether a Virtual Energy Bid and Virtual Energy Offer submission is credit approved will take into account the credit requirements for previously determined credit approved Virtual Energy Bids and Virtual Energy Offers.

4A.3.4 If a Credit Customer cancels a credit approved Virtual Energy Bid or Virtual Energy Offer submission prior to the close of the Day-Ahead Market for the Operating Day for which it is submitted, that Virtual Energy Bid or Virtual Energy Offer will no longer have a credit requirement associated with it and its EVE will be zero.

4A.4 Updated EVE Calculations Post Day-Ahead Market Clearing. After clearing of the Day-Ahead Market for an Operating Day, the EVEs for credit approved Virtual Energy Bids and Virtual Energy Offers shall be updated to replace the maximum megawatts with the actual megawatts that cleared. If there are Virtual Energy Bids and Virtual Energy Offers that cleared at the same location, the megawatt amounts will be netted in the updated EVE calculation.

ARTICLE FIVE

Calculation of Total Potential Exposure

5.1 Overview. The Total Potential Exposure is a calculated value applied to assure that the Credit Customer engages in activities within its Total Credit Limit. The Total Potential Exposure is based on the Credit Customer's estimated cumulative financial obligation under the Tariff or otherwise to SPP. Potential Exposure to non-payment is calculated separately for each applicable category of service and then summed together to obtain the amount of Total Potential Exposure. This Article addresses the calculation and use of the value for Total Potential Exposure.

5.2 Calculation of Total Potential Exposure for a Credit Customer. A Credit Customer's Total Potential Exposure shall be the sum of the potential exposure to non-payment for market transactions billed pursuant to the Tariff.

5.2.1 Market Exposure ("ME"). Potential exposure to non-payment associated with market transactions in Markets+ is calculated under the following formula:

ME = IMSC + CMSC + MEMERT + MEMEDA + EVE

IMSC = Invoiced Market Settlement Charges (all Real-Time Balancing Market and Day-Ahead Market, including virtual transaction activity, charges or credits that have been invoiced but not yet paid).

CMSC = Calculated Market Settlement Charges (all Real-Time Balancing Market and Day-Ahead Market, including virtual transactions, daily settlement activity, including charges or credits, that has been calculated but not yet invoiced).

MEMERT = Maximum Estimated Market Exposure for Real-Time Balancing Market activity shall be the greater of:

(a) The average of the last three hundred sixty-five (365) days of daily Real Time Balancing Market settlement activity (or if settlement activity occurred for a lesser period, the average settlement activity during such lesser period), or

(b) The average of the last seven (7) days of daily Real-Time Balancing Market settlement activity (or if settlement activity occurred for a lesser period, the average settlement activity during such lesser period).

Once the greater value is determined that value is multiplied by the number of days remaining in the Potential Exposure Window. Inasmuch as the Potential Exposure

Window refers to "days before service can be terminated," the time period for purposes of calculating the MEMERT does not include additional time for service termination.

MEMEDA = Maximum Estimated Market Exposure for Day-Ahead Market activity shall be the greater of:

(a) The average of the last three hundred sixty-five (365) days of most recently calculated Settlement Statements for Day-Ahead Market activity (or if settlement activity occurred for a lesser period, the average settlement activity during such lesser period), or

(b) The average of the seven (7) most recent Operating Days for which SPP has calculated either (i) updated estimated Day-Ahead Market activity results calculated four days after the Operating Day; or (ii) initial Settlement Statements for Day Ahead Market activity (or if updated estimated activity results or settlement activity occurred for a lesser period, the average updated estimated activity and settlement activity resulting during such lesser period). The initial Settlement Statements are created at the end of the 7th calendar day following the Operating Day. As initial Settlement Statements become available such statements will be used instead of the updated estimated activity results calculated four days after the Operating Day.

For the time period prior to commencement of the Day-Ahead Market for which there are no calculated initial Settlement Statements for Day-Ahead Market activity for use in the determination of the MEMEDA for a Credit Customer, SPP shall use data representative of the expected Day-Ahead Market activity for the Credit Customer based on simulations of the Day-Ahead Market or other available information.

Once the greater value is determined that value is multiplied by the number of days remaining in the Potential Exposure Window. Inasmuch as the Potential Exposure Window refers to "days before service can be terminated," the time period for purposes of calculating the MEMEDA does not include additional time for service termination.

EVE = Estimated Virtual Exposure, calculated pursuant to Article 4A (for all credit approved Virtual Energy Bids and Virtual Energy Offers prior to the close of the Day-Ahead Market for an Operating Day or Days that have not yet been settled and cleared Virtual Energy Bids and Virtual Energy Offers)

5.2.2 Total Potential Exposure Calculation. A Credit Customer's Total Potential Exposure ("TPE") shall be the sum of the potential exposure to non-payment for market transactions billed pursuant to the Tariff.

5.3 Total Potential Exposure Violations.

5.3.1 Transaction Limits. At all times, the Credit Customer shall maintain its Total Potential Exposure to a value equal to or less than its Total Credit Limit. A "Total Potential Exposure Violation" occurs when a Credit Customer's Total Potential Exposure equals or exceeds its Total Credit Limit. SPP will regularly monitor each Credit Customer's use of services and associated financial obligations. If a Credit Customer's Total Potential Exposure equals or exceeds ninety percent (90%) of its Total Credit Limit, SPP shall promptly give notice to the Credit Customer. Failure by SPP to give this notice shall not relieve the Credit Customer of its duties under this Section.

5.3.2 Cure of Total Potential Exposure Violation. A Credit Customer shall cure a Total Potential Exposure Violation by: (i) payment to SPP of invoiced amounts to reduce the Credit Customer's Total Potential Exposure, and/or (ii) provision of Financial Security in an amount sufficient to increase the Credit Customer's Total Credit Limit, such that after making such payments of invoiced amounts and/or providing such Financial Security, the Credit Customer's Total Potential Exposure will not exceed its Total Credit Limit. The Credit Customer shall have two (2) Business Days from receipt of notice from SPP to cure the violation. SPP, in its sole discretion, may determine to treat any amount tendered under (i) as an increase of Financial Security under (ii) and not as a payment to SPP.

5.3.3 Failure to Cure Total Potential Exposure Violation. A failure to cure a Total Potential Exposure Violation as required under Section 5.3.2 is a Default. In the event of such a Default, SPP has all rights under the Tariff, and all other rights and remedies in accordance with applicable law. Without prejudice to other remedies, a Credit Customer that fails timely to cure a Total Potential Exposure Violation shall be suspended from requesting any future services, including all market services SPP may provide, unless and until the Credit Customer's Total Potential Exposure Violation is cured.

5.4. Excess Financial Security. In the event a Credit Customer has provided additional Financial Security under Section 5.3.2 to address a Total Potential Exposure Violation, and the Credit Customer's outstanding invoiced amounts subsequently return to levels preceding that violation such that the total amount of Financial Security exceeds the amount required under this Credit Policy, the Credit Customer may request return of the excess Financial Security and SPP shall comply with the request within two (2) Business Days; provided, that if SPP determines to review the Credit Assessment for the Credit

Customer due to the violation, it shall not be required to respond to the request, including return of any excess Financial Security, until two (2) Business Days after completing the new Credit Assessment.

ARTICLE SIX

Guarantees

6.1 Guaranty. A Guaranty approved by SPP transfers to the Credit Customer a portion of the Guarantor's creditworthiness and thereby increases the Credit Customer's Total Credit Limit. Unlike an Irrevocable Letter of Credit or Surety Bond, a Guaranty is not Financial Security. A Guaranty that is backed by Financial Security will have the same impact upon the Total Credit Limit as Financial Security. A Guaranty that is not backed by Financial Security is unsecured and will be considered unsecured credit in the determination of the Unsecured Credit Allowance.

6.2 Approval Process. SPP will determine whether to approve a Guaranty based upon the creditworthiness of the proposed Guarantor as though it were a Credit Customer under this Credit Policy. All Credit Information required under this Credit Policy with respect to a Credit Customer must be submitted initially for the proposed Guarantor and regularly thereafter. SPP will evaluate the Credit Information and determine any Unsecured Credit Allowance and the Total Credit Limit for the Credit Customer beneficiary of the proposed Guaranty. SPP shall have the right to revise the Unsecured Credit Allowance and Total Credit Limit from time to time based upon continued assessment of the Credit Information of the Guarantor.

6.3 Requirements for Guaranty. A Credit Customer can utilize a Guaranty if all of the following conditions are satisfied:

6.3.1 Guarantor's Satisfaction of Financial Standards under this Credit Policy. A Guarantor is subject to the same financial review procedures as a Credit Customer. A Guarantor will be eligible to provide a Guaranty to the extent, if any, of the Guarantor's creditworthiness under this Credit Policy.

6.3.2 The Form and Substance of the Guaranty Acceptable to SPP. Appendix "D" of this Credit Policy is a form of Guaranty. The Guaranty must:

6.3.2.1 Be duly authorized by the Guarantor and signed by an officer of the Guarantor

6.3.2.2 State an effective period, or provide for automatic renewal or other basis for periodicity subject to cancellation on no less than sixty (60) Calendar Days notice and provided that in all events the Guaranty is effective for all obligations of the Credit Customer undertaken prior to cancellation.

6.3.2.3 Include certification of the corporate secretary that the execution, delivery, and performance of the Guaranty have been duly authorized;

6.3.2.4 Certify that the Corporate Guaranty is not in violation of other undertakings or requirements applicable to the Guarantor, and enforceable against the Guarantor in accordance with its terms;

6.3.2.5 Obligate the Guarantor to submit Credit Information on an ongoing basis as required under this Credit Policy;

6.3.2.6 Incorporate default provisions, including default provisions referred to in Section 6.3.3;

6.3.2.7 Secure, in combination with other forms of Financial Security, all obligations of the Credit Customer under or in connection with this Tariff and/or other Agreements; and

6.3.2.8 Be supported by adequate consideration and be otherwise binding as a matter of law.

6.3.2.9 Include as an attachment thereto the resolution(s) of the board of directors or other governing body of the Guarantor authorizing the Guaranty.

6.3.3 Default. Any breach of the Guaranty by the Guarantor or the requirements of the Guarantor under this Credit Policy shall be deemed a Default of this Credit Policy and a default under the Tariff by the Guarantor and the Affiliates whose obligations are supported by the Guaranty. The following also shall be a Default of this Credit Policy and a default under the Tariff: (i) the Guaranty expires or terminates (other than in accordance with its terms or upon the written consent of SPP); (ii) the Guarantor disaffirms, disclaims, repudiates, rejects or challenges the validity of all or any part of the Guaranty; or (iii) the Guaranty or any material provision of the Guaranty ceases to be in full force and effect (other than in accordance with its terms or upon the written consent of SPP).

6.4 Guaranty for Affiliates. A single Guaranty may support the Total Credit Limits of Affiliates. With respect to such a Guaranty, the sum value of the Unsecured Credit Allowance of all such Affiliates and the Guarantor shall not exceed the lesser of:

(i) the approved Unsecured Credit Allowance for the Guarantor based on SPP's financial review of Guarantor; or

(ii) $50 million.

If a Guaranty is utilized to establish an Unsecured Credit Allowance for a Credit Customer, the value of the Guaranty shall be no greater than the lesser of:

(i) The credit limit imposed in the Guaranty; or

(ii) The portion of the Unsecured Credit Allowance calculated for the Guarantor that is allocated to such Credit Customer in SPP's sole discretion; provided that the Unsecured Credit Allowance calculated for the Guarantor may not exceed $50 million; or

(iii) $50 million.

6.5 Guaranties for Not-for-Profit Credit Customers. SPP shall allow other guaranties for Not for Profit Credit Customers so long as any guaranties for such customer satisfy the requirements of Section 6.3. The form in Appendix D shall be used (subject to modifications to reflect the not for profit nature of the customer and the structure of the guaranty). An example of a permissible guaranty would be individual cities guaranteeing the payments by a municipal energy entity.

6.6 Costs. The Credit Customer shall bear all costs of obtaining and maintaining the Guaranty.

6.7 Withdrawal. A Credit Customer or the Guarantor may request the withdrawal of the Guaranty by written request to SPP. A Guaranty may be withdrawn and/or terminated only upon SPP's written approval. SPP will not approve withdrawal or termination of a Guaranty unless and until:

(i) alternate Financial Security acceptable to SPP has been provided; or

(ii) all financial obligations of a Credit Customer under the Agreements have been irrevocably satisfied in full, all Service Agreements have been terminated, and the Credit Customer is no longer a Credit Customer.

ARTICLE SEVEN

Financial Security

7.1 Acceptable Forms of Financial Security. Financial Security may be a Cash Deposit, an Irrevocable Letter of Credit, a Surety Bond or, for a Credit Customer that is a Federal Power Marketing Agency, a letter as specified in Section 7.1.4 of this Article. These forms of Financial Security may be submitted separately or in combination to equal the full amount of any required or provided Financial Security. In addition, SPP requires the execution of a Credit and Security Agreement (with respect to Cash Deposit, Irrevocable Letter of Credit, and/or Surety Bond).

7.1.2 Cash Deposits. A Cash Deposit will be Financial Security in accordance with this Section.

7.1.2.1 Deposit and Related Agreements. The initial Cash Deposit must be accompanied by execution and delivery of a Credit and Security Agreement in the form attached to this Credit Policy as Appendix "B." Under the Credit and Security Agreement, the Credit Customer shall grant to SPP a first priority security interest in and to any and all Cash Deposits, cash collateral, and deposit accounts held or controlled by SPP then existing or thereafter opened, and any and all proceeds of such collateral, including, without limitation, the cash and interest deposited therein. This security interest secures the prompt payment when due of any and all obligations of the Credit Customer under or in connection with the Tariff, and/or any and all other Agreements.

7.1.2.2 Segregated Account. The Cash Deposit will be placed in a segregated, interest-bearing account in SPP's name and held within the sole control of SPP solely to secure the payment of the Credit Customer's obligations to SPP and subject to the terms and conditions of the Credit and Security Agreement. All interest earned will accrue to the benefit of the Credit Customer, will be added to the segregated account, and will be deemed additional Cash Deposit; provided, that all such accrued and unpaid interest that has not been applied to satisfy the Credit Customer's obligations will be released and paid to the Credit Customer quarterly, and further provided, that SPP shall not be obligated to pay any interest to the Credit Customer or release any amount from the segregated account during any uncured Default.

7.1.2.3 Use of Cash Deposit. In the event a Credit Customer fails to make a timely payment to SPP, SPP may apply the Cash Deposit as necessary to satisfy the deficit. In such event, within three (3) Business Days, the Credit Customer must replenish the Cash Deposit in an amount equal to SPP's draw or in such other amount as SPP may require under this Credit Policy and failure to replenish shall be a Default under this Credit Policy. SPP's application of the Cash Deposit hereunder shall not cure the Default due to the Credit Customer's failure to make timely payment until and unless the Cash Deposit is timely replenished or other Financial Security is provided under Section 7.1.2.4.

7.1.2.4 Replacement of Cash Deposit. A Credit Customer may replace any part of a Cash Deposit with other Financial Security acceptable to SPP under this Credit Policy.

7.1.3 Irrevocable Letter of Credit. An Irrevocable Letter of Credit will be Financial Security in accordance with this Section.

7.1.3.1 Form, Requirements, and Related Agreement. Appendix "C" of this Credit Policy is an acceptable form of an Irrevocable Letter of Credit. SPP may accept an Irrevocable Letter of Credit, in its sole discretion, in revised form. Upon the Credit Customer's request, SPP shall provide a written explanation of why SPP did not accept that Credit Customer's proposed variation to the form of Irrevocable Letter of Credit set forth in Appendix "C" of this Credit Policy. The Credit Customer must execute the Credit and Security Agreement with respect to the Irrevocable Letter of Credit. Under the Credit and Security Agreement, the Credit Customer grants SPP a first priority security interest in and to any and all proceeds of any and all Irrevocable Letters of Credit then existing or thereafter issued with SPP as Beneficiary and the Credit Customer as Account Party under the Irrevocable Letter of Credit, including, without limitation, the cash issued upon a draw thereon. This security interest secures the prompt payment when due of any and all obligations of the Credit Customer to SPP, provided that the grant of a security interest shall not diminish SPP's rights to apply draws on the Irrevocable Letter of Credit to pay any and all amounts due.

7.1.3.2 Ratings of Issuing Financial Institution. At the time of issuance and at all times the Irrevocable Letter of Credit is outstanding, the issuer must be a financial institution organized under the laws of the United States or any state of the United States or the District of

Columbia or a branch or agency of a foreign commercial bank located in the United States, with a minimum corporate debt rating of an "A-" by S&P, "A3" by Moody's, "A-" by Fitch or an equivalent short-term debt rating by any of these agencies. SPP may accept an Irrevocable Letter of Credit from a financial institution that does not meet the debt rating requirements, provided that the Irrevocable Letter of Credit has a confirmation of third-party support (as governed by the Uniform Customs and Practice for Documentary Credits – International Chamber of Commerce Publication No. 500, Effective January 1, 1994 "UCP500" as stated in Article 9 Section B), in a form acceptable to SPP, from a financial institution that does meet or exceed the debt rating requirements stated in this Section. If after the Irrevocable Letter of Credit has been issued, the rating for the corporate debt of the financial institution is less than "A-" by S&P, "A3" by Moody's or "A-" by Fitch, SPP may give the Credit Customer notice to submit substitute Financial Security no later than three (3) Business Days after the notice.

7.1.3.3 **Costs.** The applicable Credit Customer shall bear all costs of providing and maintaining the Irrevocable Letter of Credit.

7.1.3.4 **Substitution of Irrevocable Letter of Credit.** The Credit Customer may replace an Irrevocable Letter of Credit with a substitute Irrevocable Letter of Credit or other Financial Security in form and amount acceptable to SPP. SPP will return the initial Irrevocable Letter of Credit upon receipt of an effective and acceptable substitute.

7.1.3.5 **Term and Renewal.** The Irrevocable Letter of Credit must automatically renew unless the issuing financial institution provides a notice to SPP at least ninety (90) days prior to its expiration date stating its decision not to renew the Irrevocable Letter of Credit. If the Irrevocable Letter of Credit is not renewed, at least ninety (90) days prior to its stated expiration date (a "Non-Renewal Event"), the Credit Customer must submit substitute Financial Security acceptable to SPP, in SPP's sole discretion, no later than eighty-seven (87) Calendar Days prior to the stated expiration date.

7.1.3.6 **Use of Irrevocable Letter of Credit.** In the event a Credit Customer fails to make any timely payment to SPP, SPP may draw upon the Irrevocable Letter of Credit as necessary to satisfy any and all amounts due from the Credit Customer pursuant to the

Agreements. In such event, within three (3) Business Days, the Credit Customer must replenish the Irrevocable Letter of Credit or provide SPP with other Financial Security in an amount equal to the draw or in such other amount as SPP may require under this Credit Policy, and failure to satisfy this requirement shall be a Default under this Credit Policy. In the event of such failure to make timely payment, and in addition to any other remedies available to SPP, SPP may draw down the entire Irrevocable Letter of Credit and hold the proceeds in an unsegregated account and apply such proceeds to amounts owed by the Credit Customer to SPP pursuant to the Agreements.

7.1.4 Federal Power Marketing Agency Letter. A form of letter as described in this Section will be Financial Security for a Federal Power Marketing Agency as that type of entity is defined in Article Two of this Attachment H.

Credit Customers that are Federal Power Marketing Agencies may provide Financial Security in the form of a letter, executed by an officer of the Federal Power Marketing Agency, that: (1) attests that the Federal Power Marketing Agency is lawfully authorized to participate in Markets+ and that any debt the Federal Power Marketing Agency incurs due to its participation in Markets+ is a debt of the United States; (2) identifies the current year's appropriations for the Federal Power Marketing Agency from the United States Congress; and (3) verifies that the amount of the current year's appropriations for the Federal Power Marketing Agency from the United States Congress meets or exceeds the amount required to satisfy the credit requirements set forth in this Credit Policy.

7.1.5 Surety Bond. A Surety Bond will be Financial Security in accordance with this Section.

7.1.5.1 Form, Requirements, and Related Agreement. Appendix "F" of this Credit Policy is an acceptable form of a Surety Bond. SPP may accept a Surety Bond, in its sole discretion, in revised form. Upon the Credit Customer's request, SPP shall provide a written explanation of why SPP did not accept that Credit Customer's proposed variation to the form of Surety Bond set forth in Appendix "F" of this Credit Policy. The Credit Customer must execute the Credit and Security Agreement with respect to the Surety Bond. Under the Credit and Security Agreement, the Credit Customer grants SPP a first priority security interest in and to any and all

proceeds of any and all Surety Bond then existing or thereafter issued with SPP as beneficiary and the Credit Customer as principal under the Surety Bond, including, without limitation, the cash issued upon a draw thereon. This security interest secures the prompt payment when due of any and all obligations of the Credit Customer to SPP, provided that the grant of a security interest shall not diminish SPP's rights to apply draws on the Surety Bond to pay any and all amounts due.

7.1.5.2 **Ratings of Issuing Surety.** At the time of issuance and at all times the Surety Bond is outstanding, the issuer must be a U.S. Treasury-listed surety with a certificate of authority from the insurance commissioner in each state in which the issuer conducts surety business, with a minimum financial strength rating of an "A" by A.M. Best. If after the Surety Bond has been issued, the financial strength rating of the surety is less than "A" by A.M. Best, SPP may give the Credit Customer notice to submit substitute Financial Security no later than three (3) Business Days after the notice.

7.1.5.3 **Costs.** The applicable Credit Customer shall bear all costs of providing and maintaining the Surety Bond.

7.1.5.4 **Substitution of Surety Bond.** The Credit Customer may replace a Surety Bond with a substitute Surety Bond or other Financial Security in form and amount acceptable to SPP. SPP will return the initial Surety Bond upon receipt of an effective and acceptable substitute.

7.1.5.5 **Term and Renewal.** The surety may terminate the Surety Bond upon ninety (90) Calendar Days written notice to SPP; *provided, however*, that: (i) the surety's liability hereunder shall survive such termination and remain in full force and effect as to obligations incurred by Credit Customer during the term of the Surety Bond; and (ii) in the event that Credit Customer fails to provide an acceptable form of replacement Financial Security to SPP at least eighty seven (87) Calendar Days prior to the termination of the Surety Bond, the surety shall, upon demand, without any notice other than such demand, and without any further action by SPP deliver a Cash Deposit to SPP not later than the next Business Day in the amount of the full remaining value of the Surety Bond as Financial Security for Credit Customer's obligations to SPP.

7.1.5.6 **Limits on Use of Surety Bonds.**

a) To be eligible to provide Surety Bonds on behalf of a Credit Customer the applicable surety must have a Tangible Net Worth of $1 billion or greater.

b) In no case shall SPP accept Surety Bonds with an aggregate value greater than $10 million dollars ($10,000,000) issued by any individual surety on behalf of an individual Credit Customer.

c) SPP shall not accept surety bonds with an aggregate value greater than $50 million dollars ($50,000,000) issued by any individual surety.

7.1.5.7 Use of Surety Bond. In the event a Credit Customer fails to make any timely payment to SPP, SPP may draw upon the Surety Bond as necessary to satisfy any and all amounts due from the Credit Customer pursuant to the Agreements. In such event, within three (3) Business Days, the Credit Customer must replenish the Surety Bond or provide SPP with other Financial Security in an amount equal to the draw or in such other amount as SPP may require under this Credit Policy, and failure to satisfy this requirement shall be a Default under this Credit Policy. In the event of such failure to make timely payment, and in addition to any other remedies available to SPP, SPP may draw down the entire Surety Bond and hold the proceeds in an unsegregated account and apply such proceeds to amounts owed by the Credit Customer to SPP pursuant to the Agreements. The foregoing sentence notwithstanding, upon the Credit Customer's written notice of request, SPP will treat as a Cash Deposit the proceeds of a draw over and above amounts currently due and unpaid and transfer same to a segregated account in accordance with such treatment, provided that the Credit Customer has executed a Credit and Security Agreement.

7.2 Financial Security Defaults. In addition to the breaches with respect to Financial Security identified in Section 7.1.2.3 (failure to replenish Cash Deposit), 7.1.3.6 (failure to replenish Irrevocable Letter of Credit), and 7.1.5.7 (failure to replenish a Surety Bond), any failure by an issuer of an Irrevocable Letter of Credit or Surety Bond, including, without limitation, failure to honor a demand in accordance with the terms thereof, or any breach of a Credit and Security Agreement shall be a Default under this Credit Policy and a default under the Tariff. A Default under this Credit Policy and a default under the Tariff shall also occur if: (i) the Financial Security expires or terminates (other than in accordance with its terms or upon the written consent of SPP); (ii) the person issuing the Financial Security disaffirms, disclaims, repudiates or rejects or challenges the validity of all or any part of the Financial Security; or (iii) the Financial Security or any material provision of the

Financial Security ceases to be in full force and effect (other than in accordance with its terms or upon the written consent of SPP).

ARTICLE EIGHT

Default and Remedies

8.1 Default. Any of the following shall constitute an "Event of Default" under this Credit Policy by a Credit Customer:

8.1.1 Failure to post any required Financial Security under this Credit Policy in the time period specified;

8.1.2 Reserved for Future Use;

8.1.3 Failure to pay in full any amount payable under the Tariff, unless cured in accordance with Section 8.3 of this Credit Policy;

8.1.4 A Credit Customer's involvement in financial difficulties as evidenced by: (i) its commencement of a voluntary case under Title 11 of the United States Code as from time to time in effect, or by its authorizing, by appropriate proceedings of its board of directors, general partners or other governing body, the commencement of such a voluntary case; (ii) its filing an answer or other pleading admitting or failing to deny the material allegations of a petition filed against it commencing an involuntary case under said Title 11, or seeking, consenting to or acquiescing in the relief therein provided, or by its failing to controvert timely the material allegations of any such petition; (iii) the entry of an order for relief in any involuntary case commenced under said Title 11; (iv) its seeking relief as a debtor under any applicable law, other than said Title 11, of any jurisdiction relating to the liquidation or reorganization of debtors or to modification or alteration of the rights of creditors, or by its consenting to or acquiescing in such relief; (v) the entry of an order by a court of competent jurisdiction (a) finding it to be bankrupt or insolvent, (b) ordering or approving its liquidation, reorganization or any modification or alteration of the rights of its creditors, or (c) assuming custody of, or appointing a receiver or other custodian for all or a substantial part of its property, and such entry or order shall not be vacated or stayed within ninety (90) Calendar Days; (vi) the filing of a petition under Title 11 which shall not be vacated within ninety (90) Calendar Days; or (vii) its making an assignment for the benefit of, or entering into a composition with, its creditors, or appointing or consenting to the appointment of a receiver or other custodian for all or a substantial part of its property.

8.1.5 Commission of any other Default specified under this Credit Policy, including Defaults specified in Sections 3.2.2, 5.3.3, 6.3.3, 7.1.2.3., 7.1.3.6, 7.1.5.7, and 7.2.

8.1.6 Except with respect to an event described in Sections 8.1.1 through 8.1.5, the failure to provide any of the Credit Information required under this Credit Policy in the

time periods specified, and the failure to observe or perform any of the material terms or conditions or provisions set forth in this Agreement, and such failure is not cured within two (2) Business Days after notice thereof from SPP. If such failure is a failure to provide any of the Credit Information required under this Credit Policy in the time periods specified, and the failure cannot reasonably be cured within such period, and if the Credit Customer has commenced and is diligently pursuing such cure and provides SPP with adequate assurance of due performance to protect SPP against loss arising from the failure to perform, the Credit Customer may request in writing stating the reasons for the delay and obtain an additional five (5) Business Days if the Credit Customer is a Large Company or a Small Company and ten (10) Business Days if the Credit Customer is a Not-For-Profit after the written notice of Default, as shall be necessary for the Credit Customer to cure the failure with all due diligence.

8.2 Notice of Financial Difficulties. Immediately upon the occurrence of an Event of Default as set forth in Section 8.1.4 of this Credit Policy, the Credit Customer shall provide notice to SPP and a copy of any pleadings, orders, petitions, agreements or other document initiating or filed in connection with such Event of Default.

8.3 Remedies for Default. Upon the first occurrence of a customer default as described in the Tariff or an Event of Default (except as defined in Section 8.1.4 of this Credit Policy) within a twelve-month period, SPP will take no action to suspend any Unsecured Credit Allowance as long as the default is remedied within the specified cure period. Should the first occurrence not be remedied within the specified cure period SPP will suspend any Unsecured Credit Allowance for ninety (90) Calendar Days. Upon the second customer default or Event of Default within a twelve (12) month period, SPP will suspend any Unsecured Credit Allowance for ninety (90) Calendar Days. The suspension will occur even if one or both occurrences were remedied within the specified cure period. SPP may, except to the extent such remedy is limited in this Credit Policy, exercise any rights or remedies it may have at law or in equity, including but not limited to bringing suit or otherwise initiating proceedings for monetary damages, injunctive relief, specific performance, and relief available under the Federal Power Act. If the Event of Default has not been cured by the Credit Customer within two (2) Business Days or as otherwise outlined under Section 8.1.6 after the Credit Customer's receipt of notice thereof, or, in the case of failure to pay in full amounts payable under Section 7 of the Tariff, within two (2) Business Days after the Credit Customer's receipt of notice thereof, except as may be precluded under applicable law, SPP may terminate all of the Credit Customer's rights under this Credit Policy. Such termination shall not affect any liability of the Credit Customer incurred before and existing as of such termination. In addition, and without prejudice to any other remedies, SPP reserves all rights to terminate service in accordance with the Tariff and applicable law.

Upon the first occurrence of an Event of Default as defined in Section 8.1.4 of this Credit Policy, SPP will immediately suspend the Credit Customer's Unsecured Credit Allowance

and may, at SPP's sole discretion, terminate all of the Credit Customer's rights under this Credit Policy and/or terminate service in accordance with the Tariff and applicable law. Any such termination shall not affect any liability that the Credit Customer incurred prior to and as of such termination. Upon the first occurrence of an Event of Default as defined in Section 8.1.4 of this Credit Policy, SPP also may order the Credit Customer to post additional collateral, cease one or more market transactions, or take other measures to protect SPP and other Market Participants from the Credit Customer's Default.

ARTICLE NINE

Notice

9.1 Designation of Credit Contact. Each Credit Customer shall in writing designate a management level official as the person responsible for the Credit Customer's credit-related matters under this Credit Policy ("Credit Contact"), which designation may be changed from time to time in writing, together with contact information including fax, e-mail, and courier delivery address. SPP will seek to effect delivery of notices under the Credit Policy to the Credit Contact in the first instance; however, if delivery to the Credit Contact fails, then SPP may effect delivery to any officer, executive, or manager of the Credit Customer.

9.2 Notices to SPP. Any notice or request made by SPP shall be given in writing, by fax, email, hand delivery, reputable overnight courier, or first-class mail, to the Credit Customer's Credit Contact. Notice to SPP shall be addressed to:

Southwest Power Pool, Inc.
Credit and Risk Management Department
201 Worthen Drive
Little Rock, AR 72223-4936

Appendix "A"

Credit Application Form

Credit Customer Identification

1.1 Name of the Company as identified in its certificate of formation / incorporation

_____

1.2 Date of formation / incorporation of the Company

_____

1.3 Registration / file number with the applicable Secretary of State's Office

_____

1.4 Please indicate all unique Company identifiers.

Company Ticker Symbol	
Market Cap	
Federal Tax ID Number	
NERC Acronym	
SIC Code	
DUNS Number	

1.5 Address of the registered office of the Company

Country	
Address	
Post Code	
City	
Phone	
Website	

1.6 Address of the trading office(s) of the Company

Country	
Address	
Post Code	
City	
Phone	
Website	

1.7 Please list any Affiliates, including subsidiary companies of which your Company owns greater than 10%, that participate in Markets+ or any Independent System Operator or Regional Transmission Operator (ISO/RTO) markets.

Affiliates	Markets+ / ISO / RTO

1.8 What is the main business of your Company (if stated in the Company's certificate of incorporation, limited liability company agreement, partnership agreement or other applicable corporate governing documents)?

_____

1.9 Please include a copy of your Company's Articles of Incorporation,Articles of Organization or similar documents.

Board, Shareholder, and Management Information

2.1 Please list board members (if applicable).

Full Name	Business Mailing Address

2.2 Please list any legal representatives (executive officers such as CEO, CFO, CRO, etc.) authorized to sign an agreement with SPP on behalf of the Company.

Full name	Authorized to sign?	Business Mailing Address	Tenure with Company
	☐ alone ☐ jointly		
	☐ alone ☐ jointly		
	☐ alone ☐ jointly		

2.3 Please state your Company's shareholders/owners and indicate their respective share or ownership percentage (>10%).

Full name	Percentage	Business Mailing Address

2.4 Please provide the following information for each individual, if any, who, directly or indirectly, through any contract, arrangement, understanding, relationship or otherwise, owns 25% or more of the equity interests of the Company.

Full name	Business Mailing Address

2.5 Please list the persons responsible, respectively, for payment of invoices, compliance, credit, trading activity and questions about this form.

Full name	Business Mailing Address	Contact details (business e-mail address and business phone number)
Payments:		
Compliance:		
Credit:		
Trading:		
Questions about responses on this form:		

SPP Market Participation

3.1 Please indicate which of SPP's products your Company transacts or intends to transact and include an estimate of the annual volumes by product (in MWh).

Real-Time Energy	
Day-Ahead Energy	
Virtual Energy	

3.2 Please list forms of credit your Company intends to utilize to support trading exposure.

Cash (See Section 7.1.2 and Appendix B)	
Irrevocable Letter of Credit (See Section 7.1.3 and Appendices B and C)	List Bank Counterparty
Corporate Guarantee (See Section 3.1.3, Article Six, and Appendix D)	List Potential Guarantor
Surety Bond (See Section 7.1.5 and Appendices B and F)	List Issuing Surety

3.3 List your Company's financial auditors and their addresses.

_____

3.4 Please provide audited financial statements for the Company for the last three years, including any current third-party credit ratings.

_____

Loss Contingencies and Judgments

4.1 Has your Company (or an Affiliate), in the last five years: a) consented to the appointment of, or was taken in possession by, a receiver, trustee, custodian or liquidator of a substantial part of its assets, b) filed a bankruptcy petition in any bankruptcy court proceeding, c) answered, consented, or sought relief under any bankruptcy or similar law or failed to obtain a dismissal of an involuntary petition, d) admitted in writing its inability to pay its debts when due, e) made a general assignment for the benefit of creditors, f) been the subject of an involuntary proceeding seeking to adjudicate the Company (or affiliate) bankrupt or insolvent, g) sought reorganization, arrangement, adjustment, or composition of it or its debt under any law relating to bankruptcy, insolvency, or reorganization or relief of debtors?

_____

4.2 If yes to any question in 4.1, please provide a description of proceedings including applicable docket or case numbers.

_____

4.3 Has your Company (or one or more of its affiliates), in the last five years, been found in violation of SEC, OCC, FERC, or CFTC requirements or any other federal or state regulation or law regarding energy commodities? Additionally, if not found in violation of such regulations and/or laws, has your Company (or its affiliates)publicly settled allegations of violation with the applicable regulatory authority and/or paid fines related to activity in energy commodities?

If yes to any question in 4.3, please provide a description of proceedings including applicable docket or case numbers.

_____

4.4 Has your Company ever failed to cure an unpaid invoice from any RTO/ISO in the last 5 years, or been found to be in default by an RTO/ISO, or been either suspended or expelled (i.e., had its participation revoked) from an ISO/RTO?

If yes to any question in 4.4, please provide an explanation of the situation, its outcome, and all other relevant factors associated with the event (including applicable docket or case numbers).

_____

Signatures

The undersigned is duly authorized to declare and does hereby declare in good faith that all information, answers and documents provided with this Questionnaire are true, correct and authentic and that no relevant information is omitted.

Place	Date	Print Name: Title:
Signature		

Subscribed and sworn before me _____, a notary public of the State of _____, in and for the County of _____, this __ day of _____, 20_____.

_____

(Notary Public Signature)
My commission expires:__/__/__

Additional Not-For-Profit Questions

Additional sheets may be added to fully answer the following questions.

1. **Does your company have the ability to set its own rates? If yes, please attach any documentation that will show that ability.**

2. **What are the terms and expiration dates of your company's wholesale power contracts?**

3. **How many customers do you serve directly? When considering your five largest customers that you directly serve, what percentage of your load do they represent?**

4. **Please describe your power supply portfolio and how it is used to meet your load. What percent of your load is secured by asset ownership or purchase power contracts? Are these assets or contracts long-term in nature? What are the expiration dates of your contracts? What is the fuel mix of your power supply portfolio? Do you engage in risk management activities? If so, please provide a brief summary of such activities.**

5. **How long has the present management team been in place? Please discuss their experience with the present firm and any previous experience.**

6. **Discuss your ability to access lines of credit from financial institutions.**

7. **Please discuss any other factors you want to have considered by SPP when assessing creditworthiness. If there are items concerning your financials that need explanation, please provide the explanation here.** If your company receives capital credits, please provide the associated cash portion of such capital credits, as well as the information needed to compute such an amount from your most recent audited financials.

Appendix "B" Credit and Security Agreement

This Credit and Security Agreement is effective as of the _____ day of _____, 20__, by and between _____ ("Company") and Southwest Power Pool, Inc. ("SPP").

Recitals

WHEREAS, SPP offers market services and other services as set out in the Markets+ Tariff of SPP, as may be amended and supplemented from time to time and together with all replacements and substitutes thereto (collectively, the "Tariff");

WHEREAS, SPP maintains a Credit Policy (which is Attachment H to the Tariff, as the same may be amended from time to time) in order to determine, on a case by case basis, the level of unsecured credit available to each customer who takes services under the Tariff and the form and amount of financial assurance to be required by each customer, if any;

WHEREAS, in the event Company provides financial assurance to SPP in the form of Cash Deposit, an Irrevocable Letter of Credit, a Surety Bond, or, for a Credit Customer that is a Federal Power Marketing Agency, a letter as specified in Section 7.1.4 of Attachment H, SPP requires Company, in accordance with the terms of its Credit Policy as filed and accepted by FERC, to execute this Credit and Security Agreement in order to assure the strength of SPP's security interest in such Cash Deposit and the proceeds of any Federal Power Marketing Agency Letter, Irrevocable Letter of Credit, or Surety Bond;

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged by each of the parties hereto, Company and SPP hereby agree as follows:

(1) The "Liabilities" as used in this Credit and Security Agreement means all of the financial obligations of the Company under the Tariff and/or any and all agreements entered into, under, pursuant to, or in connection with the Tariff (including, without limitation, the SPP Credit Policy) and any and all other agreements to which SPP and the Company are parties (collectively, the "Agreements").

(2) As security for the payment and performance of the Liabilities, SPP shall have, and the Company hereby grants to SPP, a continuing security interest in the following collateral (as indicated below) (the "Collateral"): all of the Company's right, title, and interest in any and all cash, cash collateral, Cash Deposits and deposit accounts of the Company held or controlled by SPP, including accounts designated "for the benefit of" Company, that either (i) are or contain proceeds from any draw upon any Irrevocable Letter of Credit or Surety Bond naming SPP as beneficiary to the extent that SPP determines in its sole discretion to treat such payments as cash collateral, and without prejudice to SPP's right to treat draws as payments to SPP of any and all amounts due to SPP from the Company, or (ii) are or contain cash submitted by the Company as collateral or security, however created or evidenced, whether now existing or hereafter owned, acquired, created, used or arising, including all products and proceeds of the foregoing, any and

all renewals, extensions, replacements, modifications, additions, and substitutions of the foregoing and all rights, remedies, claims and demands under or in connection with each of the foregoing.

(3) All Collateral held or controlled by SPP after the date of this Credit and Security Agreement shall be free of any lien, security interest or encumbrance, except for liens, security interests or encumbrances in favor of SPP, and the Company agrees not to grant any security interest or permit any lien or encumbrance to arise in any of the Collateral except for security interests, liens and encumbrances in favor of SPP without the prior written consent of SPP.

(4) The Company agrees to do such reasonable acts and things and deliver or cause to be delivered such other documents as SPP may reasonably deem necessary to establish and maintain a valid perfected security interest in the Collateral (free of all other liens and claims except those of SPP) to secure the payment and performance of the Liabilities and to defend title to the Collateral against any person claiming any interest therein adverse to SPP. The Company authorizes SPP to file a financing statement or statements on its behalf in those public offices deemed advisable or necessary by SPP to protect the security interest of the Company herein granted. If permitted by law, the Company agrees that a carbon, photographic or other reproduction of this Credit and Security Agreement or of a financing statement may be filed as a financing statement.

(5) Subject to the Tariff, upon the occurrence of any Default and at any time thereafter, SPP shall have all rights and remedies available at law or in equity including, without limitation, the rights and remedies of a secured party under the Arkansas Uniform Commercial Code, as in effect from time to time, including, without limitation, the right to retain and/or take possession of the Collateral. SPP may in its discretion transfer any property constituting Collateral into its own name or that of its nominee and receive the income thereon and hold the same as security for the Liabilities or apply it on amounts due on Liabilities.

(6) Until such time as SPP exercises its remedies upon a Default, all income, earnings and profits with respect to the Collateral shall be reported for state and federal income tax purposes as attributable to the Company and not SPP. Company hereby instructs SPP (and any other person authorized to report taxable income distributions) to issue, or cause to be issued, IRS Form 1099 (or Form 1042-S if a non-US person) indicating the Company as the recipient of such income, earnings and profits.

(7) Whenever possible each provision of this Credit and Security Agreement shall be interpreted in such a manner as to be effective and valid under applicable law, but if any provision of this Credit and Security Agreement shall be prohibited by or invalid under applicable law, such provision shall be ineffective only to the extent of such prohibition without invalidating the remainder of such provision or the remaining provisions of this Credit and Security Agreement. The Company recognizes that SPP has relied on this Credit and Security Agreement in extending credit to the Company and agrees that such reliance by SPP shall be sufficient consideration for this Credit and Security Agreement.

(8) The Company maintains any and all rights under Section 206 of the Federal Power Act it may have with regard to this Credit and Security Agreement or its implementation.

This Credit and Security Agreement shall be construed and enforced in accordance with, and governed by, the laws of the State of Arkansas (without giving effect to the principles of conflicts of laws).

_____
Company Name

_____
Authorized Signature

_____
Print Name

_____
Title

SOUTHWEST POWER POOL, INC.
By:

_____
Authorized Signature

_____
Print Name

_____
Title

Appendix "C" Form of Irrevocable Standby Letter of Credit

Irrevocable Standby Letter of Credit No. _____
Issued: [Date]
Expires at our counter (unless evergreen): [Date]

Ladies and Gentlemen:

We do hereby issue this Irrevocable Non-Transferable Standby Letter of Credit No. _____ by order of, for the account of and on behalf of _____ ("Account Party") and in favor of Southwest Power Pool, Inc. ("Beneficiary" or "SPP") ("Letter of Credit").

This Letter of Credit is irrevocable and is issued, presentable and payable and we guaranty to the Beneficiary of this Letter of Credit that drafts drawn under and in compliance with the terms of this Letter of Credit will be honored on presentation and surrender of certain documents pursuant to the terms of this Letter of Credit.

This Letter of Credit is available in one or more drafts and may be drawn hereunder for the account of Account Party up to an aggregate amount not exceeding $ _____ .00 (United States Dollars _____ and 00/100).

This Letter of Credit is drawn against by presentation to us at our office located at the following address:

_____
_____

of a drawing certificate: (i) Signed by an officer or authorized agent of the Beneficiary; (ii) dated the date of presentation; and (iii) containing one (1) of the following statements:

1. "The undersigned hereby certifies to _____ ("Issuer"), with reference to its Irrevocable Non-Transferable Standby Letter of Credit No. _____, dated _____, issued on behalf of _____ ("Account Party") and in favor of Southwest Power Pool, Inc. ("Beneficiary") that said Account Party has failed to make a payment in accordance with the terms and provisions of one or more of the following, as applicable: SPP's Tariff, as may be amended and supplemented from time to time, together with all replacements and substitutes (the "Tariff"), any and all agreements entered into by Account Party under, pursuant to, or in connection with the Tariff and any and all agreements to which Account Party and SPP are parties, as such agreements may be amended and supplemented from time to time, whether now or hereafter executed, and any replacements or substitutions thereof, (collectively, the "Agreements"). The Beneficiary hereby draws upon the Letter of Credit in an amount

equal to $ _____ (United States Dollars _____ and 00/100)"; or

2. "Aas of the close of business on _____, 20__ (fill in date which is less than eighty-seven (87) Calendar Days before the expiration date of the Letter of Credit), Account Party has failed to renew, replace or amend the Letter of Credit in a manner acceptable to Beneficiary." The Beneficiary hereby draws upon the Letter of Credit in an amount equal to $_____ (United States Dollars _____ and 00/100)"; or

3. "Aa of the close of business on _____, 20__ (fill in date which is more than three (3) Business Days after the Beneficiary has requested that Account Party replace the Letter of Credit because the Issuer's corporate debt is rated less than "A-" by S&P, "A3" by Moody's, "A-" by Duff & Phelps, or "A-" by Fitch), Account Party has failed to replace the Letter of Credit in a manner acceptable to Beneficiary." The Beneficiary hereby draws upon the Letter of Credit in an amount equal to $_____ (United States Dollars __ _____ and 00/100)".

Beneficiary shall have the right, in the event of a draw pursuant to subparagraph (2) or (3) of the immediately preceding paragraph, to draw down the entire face value of the Letter of Credit.

If presentation of any drawing certificate is made on a business day and such presentations made on or before 10:00 a.m._____ Time, ("Issuer") shall satisfy such drawing request on the same business day. If the drawing certificate is received after 10:00 a.m._____ Time, ("Issuer") will satisfy such drawing request on the next business day.

It is a condition of this Letter of Credit that it will be automatically extended without amendment for one year from the expiration date hereof, or any future expiration date, unless at least 90 Calendar Days prior to any expiration date we notify you by registered mail or overnight courier that we elect not to consider this Letter of Credit extended for any such period.

This Letter of Credit may be terminated upon Beneficiary's receipt of full payment from the Account Party and Issuer's receipt of a written release from the Beneficiary releasing the Issuer from its obligations under this Letter of Credit.
Disbursements under the Letter of Credit shall be in accordance with the following terms and conditions:

1. The amount, which may be drawn by the Beneficiary under this Letter of Credit, shall be automatically reduced by the amount of any drawings hereunder.

2. All commissions and charges will be borne by the Account Party.

3. This Letter of Credit may not be transferred or assigned by the Issuer.

4. This Letter of Credit is irrevocable.

5. Except when the amount of this Letter of Credit is increased this Letter of Credit may not be amended, changed or modified without the express written consent of the Beneficiary and the Issuer. Such consent may be delivered by electronic means including electronic mail to - _____.

6. This Letter of Credit shall be governed by the International Standby Practices Publication No. 590 of the International Chamber of Commerce, including any amendments, modifications or revisions thereof ("ISP98"), except to the extent that terms hereof are inconsistent with the provisions of the ISP, in which case the terms of the Letter of Credit shall govern. This Letter of Credit shall be governed by the internal laws of the state of Arkansas to the extent that the terms of the ISP are not applicable; provided that, in the event of any conflict between ISP98 and such Arkansas laws, ISP98 shall control.

_____ _____

[Authorized Signature] [Date]

Name: _____

Title:_____

Appendix "D" Guaranty Form

GUARANTY AGREEMENT

This Guaranty Agreement (the "Guaranty") is made by _____ ("Guarantor"), a _____ corporation, in favor of Southwest Power Pool, Inc. ("Creditor"), an Arkansas nonprofit corporation.

WHEREAS, one or more direct or indirect subsidiaries of the Guarantor (each referred to individually as "Debtor" and collectively as "Debtors") and the Creditor are parties to certain agreements pursuant to, or in connection with, the Creditor's Markets+ Tariff, whether now existing or hereafter arising in accordance with their respective terms (each referred to individually as "Agreement" and collectively as "Agreements");

WHEREAS, Guarantor is the direct or indirect parent of the Debtor, will receive substantial and direct benefit from the extensions of credit contemplated by the Agreements, and has agreed to enter into this Guaranty to provide assurance for the performance of Debtor's obligations in connection with the Agreements and to induce the Creditor to enter into the Agreements; and

WHEREAS, the execution and delivery of this Guaranty is a condition to Creditor's further performance of its obligations under the terms of the Agreements;

NOW, THEREFORE, in consideration of the promises and other good and valuable consideration, the adequacy, receipt and sufficiency of which are hereby acknowledged, Guarantor hereby agrees as follows:

1. **Guaranty.** Guarantor hereby unconditionally and absolutely guarantees the punctual payment as and when due of Debtor's payment obligations arising under any Agreement, as such Agreement may be amended or modified from time to time, together with any interest thereon to the extent provided in the Agreements (collectively, the "Guaranteed Obligations"). Guarantor's obligations and liability under this Guaranty shall be limited to payment obligations only and Guarantor shall have no obligation otherwise to perform under any Agreement, including, without limitation, to sell, deliver, purchase, receive, or transmit any electrical energy product or service.

2. **Guaranty Absolute.** The liability of Guarantor under this Guaranty shall be absolute and unconditional irrespective of:

   (a) any lack of validity or enforceability of or defect or deficiency in any Agreement or any other documents executed in connection with any Agreement;

   (b) any modification, extension or waiver of any of the terms of any Agreement;

(c) any change in the time, manner, terms or place of payment of or in any other term of, all or any of the Guaranteed Obligations, or any other amendment or waiver of or any consent to departure from any Agreement or any other agreement or instrument executed in connection therewith;

(d) any sale, exchange, release or non-perfection of any property standing as security for the liabilities hereby guaranteed, or any liabilities incurred directly or indirectly hereunder or any setoff against any of said liabilities, or any release or amendment or waiver of or consent to departure from this Guaranty or any other guaranty, for all or any of the Guaranteed Obligations;

(e) except as to applicable statutes of limitation, failure, omission, delay, waiver or refusal by Creditor to exercise, in whole or in part, any right or remedy held by Creditor with respect to any Agreement or any transaction under any Agreement;

(f) any change in the existence, structure or ownership of Guarantor or any Debtor, or any insolvency, bankruptcy, reorganization or other similar proceeding affecting any Debtor or its assets; or

(g) any other circumstance that might otherwise constitute a defense available to, or a discharge of, any Debtor or any other individual, partnership, joint venture, corporation, association, trust or other enterprise that is a party to any Agreement, or any other agreement or instrument (including any guarantor) in respect of the Guaranteed Obligations, other than payment in full of the Guaranteed Obligations.

The obligations of the Guarantor hereunder are several from any Debtor or any other person, and are primary obligations concerning which the Guarantor is the principal obligor. There are no conditions precedent to the enforcement of this Guaranty, except as expressly contained herein. It shall not be necessary for Creditor, in order to enforce payment by Guarantor under this Guaranty, to show any proof of any Debtor's default to exhaust its remedies against any Debtor, any other guarantor, or any other person liable for the payment or performance of the Guaranteed Obligations. Creditor shall not be required to mitigate damages or take any other action to reduce, collect, or enforce the Guaranteed Obligations.

This Guaranty shall continue to be effective or be reinstated, as the case may be, if at any time any payment of any of the Guaranteed Obligations are annulled, set aside, invalidated, declared to be fraudulent or preferential, rescinded or must otherwise be returned, refunded or repaid by Creditor upon the insolvency, bankruptcy, dissolution, liquidation or reorganization of Debtor or any other guarantor, or upon or as a result of the appointment of a receiver, intervenor or conservator of, or trustee or similar officer for, Debtor or any other guarantor or

any substantial part of its property or otherwise, all as though such payment or payments had not been made.

3. **Waiver.** This is a guaranty of payment and not of collection. Guarantor hereby waives:

(a) notice of acceptance of this Guaranty, of the creation or existence of any of the Guaranteed Obligations and of any action by Creditor in reliance hereon or in connection herewith;

(b) notice of the entry into any Agreement between any Debtor and the Creditor and of any amendments, supplements or modifications thereto; or any waiver of consent under any Agreement, including waivers of the payment and performance of the obligations thereunder;

(c) notice of any increase, reduction or rearrangement of any Debtor's obligations under any Agreement or any extension of time for the payment of any sums due and payable to the Creditor under any Agreement;

(d) except as expressly set forth herein, presentment, demand for payment, notice of dishonor or nonpayment, protest and notice of protest or any other notice of any other kind with respect to the Guaranteed Obligations; and

(e) any requirement that suit be brought against, or any other action by Creditor be taken against, or any notice of default or other notice be given to, or any demand be made on, Debtor or any other person, or that any other action be taken or not taken as a condition to Guarantor's liability for the Guaranteed Obligations under this Guaranty or as a condition to the enforcement of this Guaranty against Guarantor.

4. **Expenses.** Notwithstanding and in addition to the limit on Guarantor's liability hereunder set forth in Section 1, Guarantor agrees to pay on demand any and all costs, including reasonable legal fees and expenses, and other expenses incurred by Creditor in enforcing Guarantor's payment obligations under this Guaranty; provided that the Guarantor shall not be liable for any expenses of Creditor if no payment under this Guaranty is due.

5. **Subrogation.** Guarantor shall be subrogated to all rights of Creditor against the Debtors in respect of any amounts paid by Guarantor pursuant to this Guaranty, provided that Guarantor waives any rights it may acquire by way of subrogation under this Guaranty, by any payment made hereunder or otherwise (including, without limitation, any statutory rights of subrogation under Section 509 of the Bankruptcy Code, 11 U.S.C. § 509, or otherwise), reimbursement, exoneration, contribution, indemnification, or any right to participate in any claim or remedy of the Creditor against any Debtor or any collateral which the Creditor now has or acquires, until all of the Guaranteed Obligations shall have

been irrevocably paid to Creditor in full. If any amount shall be paid to the Guarantor on account of such subrogation rights at any time when all the Guaranteed Obligations shall not have been paid in full, such amount shall be held in trust for the benefit of Creditor and shall forthwith be paid to Creditor to be applied to the Guaranteed Obligations. If (a) the Guarantor shall perform and shall make payment to Creditor of all or any part of the Guaranteed Obligations and (b) all the Guaranteed Obligations shall have been paid in full, Creditor shall, at the Guarantor's request, execute and deliver to the Guarantor appropriate documents necessary to evidence the transfer by subrogation to the Guarantor of any interest in the Guaranteed Obligations resulting from such payment by Guarantor.

6. **Setoff.** The Creditor is hereby authorized at any time, to the fullest extent permitted by law, to set off and apply any deposits (general or special, time or demand, provisional or final) and other indebtedness owing by the Creditor to or for the account of Guarantor against any and all of the obligations of Guarantor under this Guaranty, irrespective of whether or not the Creditor shall have made any demand under this Guaranty or such Agreement and although such obligations may be contingent and unmatured. The Creditor agrees promptly to notify Guarantor after any such set-off and application made by the Creditor provided that the failure to give such notice shall not affect the validity of such set-off and application.

7. **Notices.** All demands, notices and other communications provided for hereunder shall, unless otherwise specifically provided herein, (a) be in writing addressed to the party receiving the notice at the address set forth below or at such other address as may be designated by written notice, from time to time, to the other party, and (b) be effective upon delivery, when mailed by U.S. mail, registered or certified, return receipt requested, postage prepaid, by express courier with traceable receipt, or personally delivered. Notices shall be sent to the following addresses:

If to Creditor:
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Attention: Credit and Risk Management Department

If to Guarantor:
_____
_____
_____
_____

8. **Demand and Payment.** Any demand by Creditor for payment hereunder shall be in writing, signed by a duly authorized officer of Creditor and delivered to the Guarantor pursuant to Section 7 hereof, and shall (a) reference this Guaranty, (b) specifically identify

the Debtor, the Guaranteed Obligations to be paid and the amount of such Guaranteed Obligations, and (c) set forth payment instructions. There are no other requirements of notice, presentment or demand. Guarantor shall pay, or cause to be paid, such Guaranteed Obligations within two (2) business days of receipt of such demand.

9. **No Waiver; Remedies.** Except as to applicable statutes of limitation, no failure on the part of Creditor to exercise, and no delay in exercising, any right hereunder shall operate as a waiver thereof, nor shall any single or partial exercise of any right hereunder preclude any other or further exercise thereof or the exercise of any other right. The remedies herein provided are cumulative and not exclusive of any remedies provided by law.

10. **Term; Termination.** This Guaranty shall continue in full force and effect for the term of the Agreements. Notwithstanding the foregoing, this Guaranty may be terminated at any time by the Guarantor by providing at least sixty (60) Calendar Days prior written notice to Creditor; provided, however, upon termination hereof, Guarantor agrees that the obligations and liabilities hereunder shall continue in full force and effect with respect to any Guaranteed Obligations incurred prior to the termination date, and any fees and costs of enforcement in connection herewith.

11. **Assignment; Successors and Assigns.** Creditor may, upon notice to Guarantor, assign its rights hereunder without the consent of Guarantor. Guarantor may assign its rights hereunder with the prior written consent of Creditor, which consent shall not be unreasonably withheld. Subject to the foregoing, this Guaranty shall be binding upon and inure to the benefit of the parties hereto and their respective successors, permitted assigns, and legal representatives.

12. **Amendments, Etc.** A written amendment executed by the Guarantor only may (a) increase the guaranty limit specified in Section 1 and/or (b) extend the termination date of this Guaranty. No other amendment of this Guaranty shall be effective unless in writing and signed by Guarantor and Creditor. No waiver of any provision of this Guaranty nor consent to any departure by Guarantor therefrom shall in any event be effective unless such waiver shall be in writing and signed by Creditor. Any such waiver shall be effective only in the specific instance and for the specific purpose for which it was given.

13. **Captions.** The captions in this Guaranty have been inserted for convenience only and shall be given no substantive meaning or significance whatsoever in construing the terms and provisions of this Guaranty.

14. **Representation and Warranties.**

The Guarantor represents and warrants as follows:

(a) the Guarantor is duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Guaranty. This representation is evidenced by a copy of the resolution(s) of the board of directors or other governing body of the Guarantor authorizing this Guaranty, which is attached to and made a part of this Guaranty;

(b) the execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary corporate action and do not contravene the Guarantor's constitutional documents or any contractual restriction binding on the Guarantor or its assets;

(c) this Guaranty is not in violation of other undertakings or requirements applicable to Guarantor, and is enforceable against the Guarantor in accordance with these terms;

(d) this Guaranty constitutes the legal, valid and binding obligation of the Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other laws of general applicability relating to or affecting Creditor's rights and to general equity principles; and

(e) the audited financial statements of Guarantor for the most recent fiscal year and the unaudited financial statements of Guarantor for the most recent quarter (the "Financial Statements"), heretofore delivered to Creditor, filed with the United States Securities Exchange Commission by Guarantor present fairly the financial condition and results of operations of Guarantor and its consolidated subsidiaries as of the dates and for the period specified therein in conformity withUnited States generally accepted accounting principles, and, except as otherwise expressly stated therein, consistently applied. Except as expressly stated to Creditor in writing, there has been no Material Adverse Change, as that term is defined in the Creditor's Tariff, in the financial condition of Guarantor and its consolidated subsidiaries since the dates of the Financial Statements.

15. **Limitation by Law.** All rights, remedies and powers provided in this Guaranty may be exercised only to the extent that the exercise thereof does not violate any applicable provision of law, and all the provisions of this Guaranty are intended to be subject to all applicable mandatory provisions of law that may be controlling and to be limited to the extent necessary so that they will not render this Guaranty invalid, unenforceable, in whole or in part, or not entitled to be recorded, registered or filed under the provisions of any applicable law.

16. GOVERNING LAW; SUBMISSION TO EXCLUSIVE JURISDICTION. THIS GUARANTY SHALL BE GOVERNED BY, AND CONSTRUED IN

ACCORDANCE WITH, THE LAWS OF THE STATE OF ARKANSAS AND ANY APPLICABLE FEDERAL LAW. TO THE EXTENT PERMITTED BY APPLICABLE LAW, THE PARTIES HERETO HEREBY SUBMIT TO THE EXCLUSIVE JURISDICTION OF ANY ARKANSAS STATE COURT SITTING IN PULASKI COUNTY, ARKANSAS, OR THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF ARKANSAS, FOR THE PURPOSES OF ALL LEGAL PROCEEDINGS ARISING OUT OF OR RELATING TO THIS GUARANTY OR THE TRANSACTIONS CONTEMPLATED HEREBY. THE PARTIES HEREBY WAIVE ANY OBJECTION TO VENUE INPULASKI COUNTY, ARKANSAS, AND ANY OBJECTION TO ANY ACTION OR PROCEEDING ON THE BASIS OF FORUM NON CONVENIENS.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered by its duly authorized officer effective as of this ___ day of _____, _____ ("Effective Date").

[GUARANTOR]

By: _____
Name: _____
Title: _____

Appendix "E" Annual Minimum Market Participation Criteria and Risk Management Certification Form

SPP ANNUAL MINIMUM MARKET PARTICIPATION CRITERIA – RISK MANAGEMENT CERTIFICATION FORM

I, _____, a duly authorized officer of _____ ("Market Participant"), understanding that Southwest Power Pool, Inc. ("SPP") is relying on this certification as evidence supporting SPP's determination that Market Participant meets the risk management and minimum market participation requirements as set forth in Attachment H to SPP's Markets+ Tariff ("Tariff"), hereby certify that I have full authority to certify and represent on behalf of Market Participant and further certify and represent as follows:

1. Training. Employees or agents transacting in markets or services provided pursuant to the Tariff on behalf of the Market Participant have received, or will receive, applicable training with regard to their participation under the Tariff as a condition of being authorized to transact on behalf of Market Participant. As used in this representation, training is deemed 'applicable' where it is commensurate and proportional in sophistication, scope and frequency to the volume of transactions and the nature and extent of the risk taken by the Market Participant.

2. Risk Management. Market Participant maintains current written risk management policies and procedures that address those risks that could materially affect Market Participant's ability to pay its SPP invoices when due, including, but not limited to, credit risks, liquidity risks and market risks.

3. Operational Capabilities. Market Participant has available appropriate personnel resources, operating procedures, and technical abilities to promptly and effectively respond to SPP communications and directions related to, but not limited to, settlements, billing, credit requirements and other financial matters.

4. Minimum Participation Criteria. Market Participant meets or exceeds the minimum market participation criteria, including capitalization requirements, as specified in Section 3.1.1.8 of Attachment H of the Tariff. The Market Participant shall submit audited financial statements for the most recent fiscal year to demonstrate minimum Tangible Net Worth or minimum total assets, or provide a report produced by a Rating Agency to establish its Credit Rating as specified in Section 3.1.1.8.2. In the event the Market Participant is unable to meet at least one of these minimum financial requirements, the Market Participant shall maintain with SPP the amount of Financial Security required by Section 3.1.1.8.2(e) of Attachment H to the Tariff.

Date: _____

_____
(Signature)

Print Name: _____

Title: _____

Subscribed and sworn before me _____, a notary public of the State of _____, in and for the County of _____, this __ day of _____, 20____.

_____

(Notary Public Signature)
My commission expires: _____

Appendix "F" FORM OF SURETY BOND

Surety Bond No._____

THIS SURETY BOND is issued on **[date]** by **[full legal name of surety]** ("Surety") on behalf of **[full legal name of SPP customer]** ("Principal"), and in favor of Southwest Power Pool, Inc. ("SPP"). Capitalized terms used and not otherwise defined herein shall have the meaning ascribed to those terms in SPP's Markets+ Tariff (the "Tariff").

WHEREAS, Principal seeks to satisfy credit or security requirements established in the Tariff; and

WHEREAS, Surety is U.S. Treasury-listed with a minimum "A" rating from A.M. Best and has agreed, in exchange for compensation provided by Principal, to provide this Surety Bond on behalf of Principal in accordance with SPP's credit requirements;

NOW, THEREFORE, in consideration of the mutual promises and covenants herein contained, Surety hereby agrees and covenants as follows:

1. Amount of Bond. Surety unconditionally and irrevocably agrees to pay SPP amounts not to exceed an aggregate of **[amount]**, in accordance with the terms of this Surety Bond.

2. Payment Upon Demand. Surety shall pay such amount as specified by SPP upon receipt of a demand for payment notice ("Demand for Payment Notice"). Such Demand for Payment Notice shall be: (i) signed by an officer or authorized agent of SPP, (ii) dated the date of presentation, and (iii) be in the form as set forth in Exhibit A, Exhibit B, or Exhibit C, as applicable.

3. Validation. SPP may demand payment pursuant to this Surety Bond without prior demonstration of the validity of the demand.

4. Multiple Draws. SPP may demand multiple payments pursuant to this Surety Bond; *provided, however*, that the total amount of Surety's obligation hereunder shall not exceed an aggregate of **[amount]**.

5. Time and Form of Payment. Surety shall pay amounts owed pursuant to this Surety Bond in full not later than the first business day following receipt of SPP's written demand for payment to the account designated therein.

6. Obligations Unconditional. This Surety Bond is not conditioned upon SPP first attempting to collect payment, resorting to any other means of security or collateral, or pursuing any other remedies it may have. The obligations of Surety hereunder are independent of the obligations of Principal, and SPP may bring an action against Surety without bringing an action against Principal. SPP may from time to time, without notice or demand, and without affecting Surety's liability

hereunder, take and hold other security for Principal's obligations to SPP and exchange, waive, release, or apply such security as SPP deems appropriate in its sole discretion. Surety's liability under this Surety Bond is not conditioned upon the validity or enforceability of Principal's obligations to SPP.

7. Term of Surety Bond. The term of this Surety Bond shall begin on the date of its issuance, as set forth above, and shall continue in full force and effect until all amounts owed by Principal pursuant to the Agreements, as that term is defined in the Tariff, are paid in full, including any amounts owed as a result of true-ups or other corrections to previous settlements; *provided, however,* that Surety may terminate this Surety Bond as provided in Paragraph 8, below.

8. Termination. Surety may terminate this Surety Bond upon ninety (90) Calendar Days written notice to SPP; *provided, however*, that: (i) Surety's liability hereunder shall survive such termination and remain in full force and effect as to obligations incurred by Principal during the term of this Surety Bond; and (ii) in the event that Principal fails to provide an acceptable form of replacement Financial Security to SPP at least eighty seven (87) Calendar Days prior to the termination of this Surety Bond, Surety shall, upon demand, without any notice other than such demand, and without any further action by SPP deliver Cash Deposit to SPP not later than the next Business Day in the amount of the full remaining value of this Surety Bond as security for Principal's obligations to SPP. A Cash Deposit provided to SPP by Surety and not applied by SPP to satisfy unpaid obligations of Principal shall be returned to Surety at such time as: (i) Principal provides adequate replacement Financial Security to SPP or (ii) all amounts owed by Principal to SPP are paid in full, including amounts owed as a result of true-ups or other corrections to previous settlements.

9. Principal Pays Bond Costs. Principal shall pay all commissions and charges for this Surety Bond. Principal's failure to pay any such charges shall not be grounds for termination of this Surety Bond, except as provided in Paragraph 8, above.

10. Expenses. Surety shall pay all reasonable costs incurred by SPP in the enforcement of this Surety Bond, including attorney fees and expenses. Surety's obligation to pay such costs shall be in addition to other amounts owed pursuant to this Surety Bond and shall not be limited by the maximum stated amount of this Surety Bond.

11. Communications. Demands, notices, and other communications shall be deemed effective when received, shall be in writing, and shall be delivered by courier with receipt of delivery or by registered mail or certified mail to the following addresses:

a. If to Surety:

[Surety notice address]

b. If to SPP:

Attn: Credit and Risk Management Department

Southwest Power Pool, Inc.

201 Worthen Drive
Little Rock, AR 72223-4936

c. If to Principal:

[Principal notice address]

Surety, SPP, or Principal may change the address provided for receipt of communications pursuant to this Surety Bond by providing written notice to the other parties.

12. Representations and Warranties. Surety represents and warrants to SPP that:

a. Surety has the legal power to execute and deliver this Surety Bond and to perform in accordance with its terms. All necessary actions have been taken to authorize the execution and delivery of this Surety Bond and performance in accordance with its terms. This Surety Bond is a legal, valid, and binding obligation of Surety.

b. There is no action or proceeding pending or, to Surety's knowledge, threatened before any court, arbitrator, or governmental agency that may materially adversely affect Surety's ability to perform its obligations under this Surety Bond.

c. There is no fact that Surety has not disclosed in writing to SPP of which Surety is aware or which Surety can reasonably foresee that would materially adversely affect Surety or the ability of Surety to perform its obligations hereunder.

13. Assignment. SPP may assign its rights under this Surety Bond without in any way diminishing Surety's obligations hereunder. Surety shall not be permitted to assign or transfer its rights under this Surety Bond without prior written consent of SPP.

14. Amendment and Waiver. The terms and provisions of this Surety Bond may not be amended or waived except in a writing signed by SPP and Surety. Election not to exercise, failure to exercise, or delay in exercising any rights under this Surety Bond shall in no way operate as a waiver of any rights of SPP under this Surety Bond.

15. Entire Agreement. This Surety Bond embodies the entire agreement between Surety and SPP with respect to the matters set forth herein and supersedes all prior such agreements.

16. Severability. Should any provision of this Surety Bond be determined by a court of competent jurisdiction to be unenforceable, all of the other provisions shall remain effective.

17. Choice of Law; Jurisdiction; Venue; and Service of Process. This Surety Bond shall be governed by the laws of the State of Arkansas without regard to conflict of laws principles. Surety

irrevocably submits to the jurisdiction of any Arkansas court or any United States court sitting in Arkansas over any action or proceeding arising out of or relating to this Surety Bond and irrevocably agrees that all claims in such action or proceeding may be heard and determined by such court. Surety agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Surety waives any objection to venue on the basis of forum non conveniens. Surety irrevocably consents to the service of process in any action or proceeding by the mailing of copies of such process to Surety at its address set forth herein. Nothing herein shall affect the right of SPP to bring any action or proceeding against Surety or its property in the courts of any other jurisdictions.

18. Waiver of Jury Trial. SURETY IRREVOCABLY, VOLUNTARILY, AND WITH ADVICE OF COUNSEL WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN ANY ACTION ARISING IN CONNECTION WITH THIS SURETY BOND.

IN WITNESS WHEREOF, Surety has executed and delivered this Surety Bond this **[date]**.

[Full Legal Name of Surety]

By: _____

Name: _____
Title: _____

EXHIBIT A

(Form of Demand for Payment Notice – Principal Failure to Make Payment)

[**Date**][1]

[**Name and Address of Surety**][2]

Re: Surety Bond No. _____
Demand for Payment

To the above named Surety:

The undersigned hereby certifies to [**full legal name of surety**] ("Surety"), with reference to its Surety Bond No. [**bond number**], dated [**execution date of Surety Bond**], issued on behalf of [**full legal name of SPP customer**] ("Principal") and in favor of Southwest Power Pool, Inc. ("SPP") that Principal has failed to make payment in accordance with the terms of the Agreements as defined in SPP's Markets+ Tariff. SPP hereby demands payment in the amount of $ [**amount**] in accordance with the following instructions.

[**Wiring Instructions**]

Southwest Power Pool, Inc.

By: _____[3]

Name: _____

Title: _____

[1] The date of the Demand for Payment Notice must be the date for which presentation of the Notice is made.
[2] This will be the address of the Surety as set forth in the Surety Bond.
[3] The undersigned must be an officer or authorized agent of SPP.

EXHIBIT B

(Form of Demand for Payment Notice – Principal Failure to Provide Acceptable Security)

[**Date**][4]

[**Name and Address of Surety**][5]

Re: Surety Bond No. _____
Demand for Payment

To the above named Surety:

The undersigned hereby certifies to [**full legal name of surety**] ("Surety"),with reference to its Surety Bond No. [**bond number**], dated [**execution date of Surety Bond**], issued on behalf of [**full legal name of SPP customer**] ("Principal") and in favor of Southwest Power Pool, Inc. ("SPP") that as of the close of business on [**date**] **[date less than eighty-seven (87) Calendar Days before the expiration of the Surety Bond]**,[6] Principal has failed to renew, replace, or amend this Surety Bond in satisfaction of the credit requirements established pursuant to SPP's Markets+ Tariff. SPP hereby demands payment in the amount of $ [**amount**] in accordance with the following instructions.

[**Wiring Instructions**]

Southwest Power Pool, Inc.

By: _____[7]

Name: _____

Title: _____

[4] The date of the Demand for Payment Notice must be the date for which presentation of the Notice is made.
[5] This will be the address of the Surety as set forth in the Surety Bond.
[6] Insert date less than eighty-seven (87) Calendar Days prior to expiration of the Surety Bond.
[7] The undersigned must be an officer or authorized agent of SPP.

EXHIBIT C

(Form of Demand for Payment Notice – Surety Rating Downgrade)

[**Date**] [8]

[**Name and Address of Surety**] [9]

Re: Surety Bond No. _____
Demand for Payment

To the above named Surety:

The undersigned hereby certifies to [**full legal name of surety**] ("Surety"),with reference to its Surety Bond No. [**bond number**], dated [**execution date of Surety Bond**], issued on behalf of [**full legal name of SPP customer**] ("Principal") and in favor of Southwest Power Pool, Inc. ("SPP") that as of the close of business on [**date**] **[date more than three (3) Business Days after SPP has requested that Principal replace the Surety Bond because the Surety's rating by A.M. Best is less than "A"]**, Principal has failed to replace this Surety Bond in a manner acceptable to SPP. SPP hereby demands payment in the amount of $ [**amount**] in accordance with the following instructions.

[**Wiring Instructions**]

Southwest Power Pool, Inc.

By: _____ [10]

Name: _____

Title: _____

[8] The date of the Demand for Payment Notice must be the date for which presentation of the Notice is made.
[9] This will be the address of the Surety as set forth in the Surety Bond.
[10] The undersigned must be an officer or authorized agent of SPP.

ATTACHMENT I
Distribution of Other Revenues

Adjustments To Revenue Allocations in the Event of Market Participant Non-Payments

If the amounts collected by SPP for Market Services are insufficient to fully pay the providers of Market Services, then the following procedures apply:

A. Definitions

The following definitions apply in this Attachment I. Capitalized terms used in this Attachment I and not defined herein shall be given the meaning assigned to them under the Tariff.

1. Credit Support Documents: Any agreement or instrument in any way guaranteeing or securing any or all of a Market Participant's obligations under the Tariff (including, without limitation, the Credit Policy in Attachment H to this Tariff), any agreement entered into under, pursuant to, or in connection with the Tariff or any agreement entered into under, pursuant to, or in connection with the Tariff or the Credit Policy, and/or any other agreement to which SPP and Market Participant are parties, including, without limitation, any Guaranty, Letter of Credit, Credit and Security Agreement (Attachment B to the Credit Policy in Attachment H to this Tariff) or agreement granting a security interest.

2. Default: Any default under Article 8 or otherwise under the Credit Policy.

3. Defaulting Market Participant: A Market Participant that defaults under Article 8 of the Credit Policy.

4. FERC: The Federal Energy Regulatory Commission.

5. Market Services: Services taken and/or provided pursuant to the Tariff.

6. Non-Defaulting Market Participants: Market Participants, other than the Defaulting Market Participant, who conducted business in the market during the time covered by the invoice(s) containing the Unpaid Obligation.

7. Unpaid Obligation: An unpaid past due amount of an invoice for Market Services for which SPP does not reasonably expect payment in full and which SPP has declared to be an Unpaid Obligation.

8. Uncollectible Obligation: An Unpaid Obligation that has not been paid within ninety (90) days after SPP declared an invoice an Unpaid Obligation, or sooner, should by any means the Market Participant's Service Agreement be terminated.

B. General

SPP shall only be required to remit to providers of Market Services the revenues that it has collected, without dispute, under the Tariff for Market Services, as applicable.

C. Procedures for Non-Payment of Amounts Invoiced for Market Services

1. The following procedures apply to defaults in payment of amounts invoiced for Market Services. At such time as SPP concludes that SPP does not reasonably expect payment in full of an unpaid past due amount, which SPP may conclude as early as within one (1) day after the due date, then SPP shall declare such unpaid past due amount to be an Unpaid Obligation. SPP will notify Market Participants of the declaration of an Unpaid Obligation. Such notification will identify the Defaulting Market Participant, the amount of the Unpaid Obligation, the applicable week(s) of service for which the Defaulting Market Participant was initially invoiced the Unpaid Obligation, and the future billing week(s) in which SPP will, because of the Unpaid Obligation, reduce the revenues to be paid to all Non-Defaulting Market Participants who conducted business in the market during the time covered by the invoice applicable to the Unpaid Obligation.

SPP will then make reduced payments on the corresponding payout date to the Non-Defaulting Market Participants receiving revenues for Market Services associated with the Unpaid Obligation. A payment to a Non-Defaulting Market Participant will be reduced in amount equal to such Non-Defaulting Market Participant's pro rata share of the Unpaid Obligation.

Upon the earliest feasible date after declaring an Unpaid Obligation, SPP will take the following additional steps: (i) identify and segregate all funds held by SPP with respect to the Defaulting Market Participant; (ii) recover the Unpaid Obligation by drawing upon the entire amount of collateral provided by the Defaulting Market Participant, provided that any amount of the Unpaid Obligation not paid by such draw shall continue to be an Unpaid Obligation; (iii) seek to recover the Unpaid Obligation from any guarantor of the Defaulting Market Participant's obligations; (iv) seek to exercise other remedies under the Credit Support Documents provided by the Defaulting Market Participant; and (v) pursue other available remedies for Defaults, including, without limitation, initiating a filing with FERC to terminate the Service Agreement of the Defaulting Market Participant. SPP may deviate from steps (i) through (v), including omission of steps and use of other measures as SPP may determine, in its discretion, are appropriate to maximize collection, minimize collection costs, and produce cost effective collection efforts relative to, for example, the likelihood of collection of the Unpaid Obligation.

Any amounts received by SPP pursuant to this Section C.1. of this Attachment I shall be applied to reduce the amount of the Unpaid Obligation if those amounts are received prior to the issuance of a notice to cure the Default. After the notice to cure is issued, Section C.2. of this Attachment I will apply.

2. Payments by Defaulting Market Participants of Unpaid Obligations. This Section I.C.2 applies to amounts invoiced to Market Participants for Market Services only.

After SPP has declared an Unpaid Obligation, SPP will send the Defaulting Market Participant a notice to cure the Default as specified in Section 8 of the SPP Credit Policy. The Defaulting Market Participant must take the following steps to cure its Default: (i) pay all unpaid obligations to SPP, including, without limitation, the amount of the Unpaid Obligation, interest, and enforcement and collection costs; and (ii) meet the creditworthiness requirements of SPP, including, without limitation, any additional financial assurances that may be required by SPP given the Defaulting Market Participant's prior Default.

In the event the Defaulting Market Participant attempts to cure its Default by making partial payment of the Unpaid Obligation, the partial payment shall not be applied to reduce the Unpaid Obligation but shall instead be segregated from other SPP funds. Such segregated partial payments shall accumulate until the full amount of the Unpaid Obligation is cured by a series of two or more partial payments. In the event SPP determines that the Unpaid Obligation is uncollectible pursuant to Section C.2. of this Attachment I and is an Uncollectible Obligation, the segregated partial payments along with any interest shall be applied using the formula set forth in Section C.3.b. of this Attachment I, and the funds will be distributed as described in Section C.3.c. of this Attachment I.

In the event the full amount of the Unpaid Obligation is paid by the Defaulting Market Participant prior to SPP declaring the Uncollectible Obligation, those revenues will be distributed to Market Participants in the same percentages as the previous reduction of revenues associated with the Unpaid Obligation.

3. Uplift. This Section C.3 of this Attachment I applies to amounts invoiced to Market Participants for Market Services only. Ninety (90) days after declaring an invoice an Unpaid Obligation or sooner, should by any means the Market Participant's Service Agreement be terminated, SPP will declare that Unpaid Obligation an Uncollectible Obligation. SPP shall proceed to recover the Uncollectible Obligation from all Market Participants who conducted

business in the market during the period covered by the invoice(s) associated with the Uncollectible Obligation(s) on a pro rata basis, with the amount of the Uncollectible Obligation adjusted by the amount of the Unpaid Obligation recovered pursuant to Section C.1. of this Attachment I and partial payments pursuant to Sections C.2. of this Attachment I.

a. Eligibility for Share of Uncollectible Obligation.

The Uncollectible Obligation shall be allocated by SPP to all Non-Defaulting Market Participants that had been invoiced by SPP during the same period of time as the unpaid invoice(s) of the Market Participant whose Unpaid Obligation has been declared an Uncollectible Obligation.

b. Uncollectible Obligation Allocation Methodology.

The formula below is the basis for allocating the Uncollectible Obligation to all Non-Defaulting Market Participants who conducted business in the market during the time covered by the invoice(s) containing the Uncollectible Obligation(s).

% Loss for MP_A =

MP_A Market Charges +
Market Credits in weekly invoicing cycle/
MP_{ALL} (Market Charges + Market Credits) in weekly invoicing cycle.

Loss Obligation of MP_A = ((% Loss for MP_A) x $ Amt of Uncollectible Obligation) minus (-) (Reduction of Payments + Pro rata share of partial payment(s))

Where:

MP = Market Participant

Market Charges = The absolute value of all charge amounts associated with invoices for Market Services.

Market Credits = The absolute value of all credit amounts associated with invoices for Market Services.

MP_{ALL} = All Market Participants other than Market Participants with Uncollectible Obligations.

Reduction of Payment = The amount of the Unpaid Obligation originally assessed to Market Participant as described in Section I.C.1. above.

Pro rata share of partial payment(s) = Any partial payments received during cure period as described in Section I.C.2.

All individual charge amounts and all individual credit amounts invoiced for Market Services shall be included in the calculation of Market Charges and Market Credits. The Market Charges and Market Credits of Market Participants with Uncollectible Obligations will not be included in the calculation of the percentage of the loss to be allocated to all Non-Defaulting Market Participants that had been invoiced by SPP during the same period of time as the unpaid invoice(s) of the Defaulting Market Participant whose Unpaid Obligation has been declared an Uncollectible Obligation.

c. Application of Recovered Uncollectible Obligation.

Any funds that are attributable to an Uncollectible Obligation that are recovered by SPP (other than amounts recovered by the uplift of the Uncollectible Obligations) after the Uncollectible Obligation has been uplifted pursuant to Section C.3.b. of this Attachment I, shall first be applied to satisfy outstanding costs of enforcement and collection of the Unpaid Obligation or Uncollectible Obligation, and any other amount due to SPP under the Tariff or any other agreements. Any remaining funds attributable to an uplifted Uncollectible Obligation, together with any remaining interest and late charges collected with respect to the uplifted Uncollectible Obligation, shall be distributed pro rata to the Non-Defaulting Market Participants, using the same formula specified under Section C.3.b. of this Attachment I to whom the Uncollectible Obligation was uplifted and who satisfied their obligation to pay the uplifted Uncollectible Obligation.

ATTACHMENT J
Allocation of Costs Associated with Penalty Assessments

The Market Operator may be assessed penalties under the North American Electric Reliability Corporation ("NERC") Functional Model and NERC Rules of Procedure for confirmed violations of the NERC Reliability Standards, or penalties assessed by FERC or other state, federal, or local government entities to the Market Operator acting in its role as the Market Operator. The purpose of this Attachment is to provide notice to all Market Participants that they may be responsible for penalties assessed against the Market Operator. If the Market Operator determines that Market Participants are responsible for or have directly contributed to, the violations at issue, the Market Operator may seek to directly assign penalty costs to Market Participants. The Market Operator may assign penalty costs to an identified group of the market if the penalty costs are a consequence of the identified group's market participation.

Under this Attachment, the Market Operator may seek, subject to approval by the SPP Board, recovery of the costs associated with any monetary penalty under Sections 205 or 206 of the Federal Power Act for recovery of penalty costs from one or more Market Participants, an allocation of penalty costs to an individual Market Participant, or among an identified group of Market Participants, or a broad allocation of penalty costs among all Market Participants.

1. Definitions

All defined terms in this Attachment shall have the meaning given to them in the Tariff unless otherwise stated below.

Federal Government Entity-- A department or agency of the United States.

Former Market Participant – An entity that was a Markets+ Participant at the time that the conduct giving rise to a penalty occurred, but that has since terminated its participation in Markets+.

2. Direct Assignment of Costs Where Violation Can Be Directly Assigned

The purpose of this Section is to provide notice to all Market Participants that they may be responsible for penalty costs assessed against the Market Operator in the event that the Market Participant's conduct or omission(s) contributed to the violation(s) for which a monetary penalty is assessed. This Section provides for notification of the potential direct assignment of penalty costs that may be assessed to the Market Operator. The Market Operator shall notify, in writing, any potentially affected Market Participants of an alleged violation as soon as possible. In addition, the Market Operator will invite the affected Market Participant(s) to fully participate in all discussions or proceedings that may lead to the assessment of penalty costs.

If a monetary penalty is assessed against the Market Operator and one or more Market Participants directly contributed to or is found to have been a "root cause(s)" of the assessment of the penalty costs, such Market Participant(s) may be assessed a portion of or all of the monetary penalty. The Market Operator may not recover any direct assignment of penalty costs until approved by the Federal Energy Regulatory Commission ("FERC") following consideration under Section 205 or Section 206 of the Federal Power Act.

3. Direct Assignment of Costs to Identified Market Participants

The purpose of this Section is to provide notice to all Market Participants that they are potentially responsible for penalty costs assessed in the event that the penalty is a consequence of the Market Participant's participation in Markets+. This includes, but is not limited to, situations where the penalty is a result of a state, regional, or local program. When the penalty is assessed to the Market Operator, the Market Operator will allocate the penalty costs among Market Participants whose market participation rendered the Market Operator subject to the state, regional, or local program penalty costs.

The Market Operator shall notify, in writing, any potentially affected Market Participants of a potential penalty as soon as practical. In addition, the Market Operator will invite the affected Market Participant(s) to fully participate in all discussions or proceedings the may lead to the assessment of a penalty.

The Market Operator may not recover any assignment or allocation of costs until approved by the Federal Energy Regulatory Commission ("FERC") following consideration under section 205 or section 206 of the Federal Power Act.

4. Allocation of Costs Where Violation Cannot Be Directly Assigned

The purpose of this Section is to provide notice to all Market Participants that they may be responsible for penalty costs assessed to the Market Operator that cannot be directly assigned under Section 2 or Section 3 of this Attachment. This Section provides for allocation of such penalty costs among all Market Participants where the Market Operator itself is assessed a penalty and the penalty is not the result of the actions or participation of any particular Market Participant or group of Market Participants.

The Market Operator will notify, in writing, any potentially affected Market Participants of a potential penalty as soon as practical. In addition, the Market Operator will invite the affected Market Participant(s) to fully participate in all discussions or proceedings the may lead to the assessment of a penalty.

The Market Operator may not recover any assignment or allocation of costs until approved by the Federal Energy Regulatory Commission ("FERC") following consideration under Section 205 or Section 206 of the Federal Power Act..

5. Penalties Allocated or Attributable to Federal Government Entities

Notwithstanding anything in this Attachment to the contrary, Federal Government Entities participating in Markets+ have not waived or conceded any defense they may have, including sovereign immunity, intergovernmental immunity, or lack of subject matter jurisdiction in any action against it by an Enforcement Authority, nor have the Federal Government Entities accepted any liability, responsibility, or obligation to pay any civil monetary penalties or fines imposed by an Enforcement Authority to which it would not have been subject in the absence of this Agreement. "Enforcement Authority" in this Agreement means any entity that may assess a

financial penalty to the Market Operator for its operation of the market. The Market Operator does not concede or accept responsibility for any portion of a penalty or fine attributable to the actions or omissions of a Federal Government Entity. The Market Operator will identify the amount of any penalty or fine that the Market Operator allocates to a Federal Government Entity, or that the Market Operator determines is attributable to a Federal Government Entity, and will identify that amount to FERC as uncollectable and not otherwise owed by the Market Operator.

6. Former Market Participants

A Former Market Participant may still be subject to allocation of a share of penalty costs arising as the result of the Former Market Participant's contribution to the violations at the time of the Former Market Participant's participation in Markets+.