of the Bidders shall not be publicly revealed, but the data shall be posted in a way that permits third parties to track each individual Bidder's Bids over time.

Upon completion of the auction, the Independent Transmission Provider will collect payment for all Congestion Revenue Rights awarded in the auction. The Independent Transmission Provider will disburse the revenues collected from the sale of Congestion Revenue Rights to the Primary Holders upon completion of the Auction process. Each holder of a Congestion Revenue Right that offers that Congestion Revenue Right for sale in the auction shall be paid the Market Clearing Price for each Congestion Revenue Right sold by that holder. All remaining Auction revenues from the auction shall be allocated among those who pay the Access Charge. [The Independent Transmission Provider will file procedures explaining how these revenues will be allocated.]

8. Exchanging Congestion Revenue Rights

The Independent Transmission Provider shall allow a Customer to exchange its Receipt Point-to-Delivery Point Congestion Revenue Right Obligation for a different Receipt Point-to-Delivery Point Congestion Revenue Right Obligation with different Receipt and/or Delivery Points as long as the exchange meets the condition specified in Section D.6.1 is met. In addition, as soon as it is technically feasible, the Independent Transmission Provider shall allow a Customer to acquire Receipt Point-to-Delivery Point Transmission Option Rights and Flowgate Rights in exchange for other Congestion Revenue Rights that the Customer may hold, as long as the exchange meets the condition specified in Section D.6.1. The MW levels of the original Congestion Revenue Rights and the new Congestion Revenue Rights in the exchange need not be the same, as long as the exchange meets the condition specified in Section D.6.1.

8.1 Condition for Exchanging Congestion Revenue Rights: In order for the Independent Transmission Provider to approve a request to exchange Congestion Revenue Rights, pursuant to Section D.6, the new Congestion Revenue Right (after being exchanged for the original Congestion Revenue Right), in combination with all other outstanding Congestion Revenue Rights held by others, must be Simultaneously Feasible as defined in Section D.5.8 in light of the total Transmission Capability in the Independent Transmission Provider's Service Area under normal operating conditions.

9. Congestion Revenue Rights Associated with Transmission Expansions

The Independent Transmission Provider shall award to all Market Participants that fund additions to the transmission system Congestion Revenue Rights to equal the capability created by the expansion. The Congestion Revenue Rights awarded in combination with all other awarded Congestion Revenue Rights, must be Simultaneously Feasible as described in Section D.5.8 in light of the Total Transfer Capability available under normal operating conditions. Such Market Participants shall be allowed to choose any set of Receipt Point-to-Delivery Point Obligation Rights that meet the requirements for Simultaneously Feasibility. Such Market Participants shall also be allowed to choose any set of Receipt Point-to-Delivery Point Option Rights and Flowgate Rights that meet the requirements for Simultaneous Feasibility, as soon as it is it is feasible to issue such rights. Such Market Participants may elect to receive no Congestion Revenue Rights if, but only if, all outstanding Congestion Revenue Rights are Simultaneously Feasible in light of the Total Transfer Capability available after the additions under normal operating conditions. [The Independent Transmission Provider file a Commission-approved, non-discriminatory methodology for allocating Congestion Revenue Rights among multiple Market Participants that fund any single transmission capability addition.]

Part III. Day-Ahead and Real-Time Market Services

E. General Responsibilities and Requirements

Preamble

The Independent Transmission Provider will operate Day-Ahead and Real-Time Markets for Energy and certain Ancillary Services in conjunction with Day-Ahead and Real-Time markets for transmission services. These markets will allocate transmission Transfer Capability and Generation Capacity among competing uses in different markets through Locational Marginal Pricing (LMP). The markets will be operated jointly to ensure that the prices for the products and services are internally consistent. The procedures for operating these markets are detailed below.

1. Day-Ahead and Real-Time Market Services

This Part III contains the procedures for Bidding and Scheduling of Energy and Bid-Based Ancillary Services, Bilateral Transaction Schedules and Self-Schedules in the Day-Ahead Market. Part III also contains the time requirements, notice provisions and sequence followed in administering Day-Ahead financial Settlement. These scheduling requirements support the operations of the Day-Ahead Markets for Energy, Regulation and Frequency Response, and Operating Reserves, the determination of the Day-Ahead Transmission Usage Charge, and the Day-Ahead financial Settlement of Congestion Revenue Rights.

Part III also contains the procedures for Scheduling and Bidding of Energy and Bid-Based Ancillary Services, and modification of, or submission of new, Bilateral Schedules and Self-Schedules, that will be used following the close of the Day-Ahead Market. These procedures include the time requirements, notice provisions and sequence followed in administering Real-Time Financial Settlement. These Bidding and scheduling requirements support the operations of the Real-Time Markets for Energy, Regulation and Frequency Response, Operating Reserves, and the determination of the Real-Time Transmission Usage Charge.

2. Independent Transmission Provider Authority

The Independent Transmission Provider shall provide all Market Services for Energy, Ancillary Services, and Transmission Service in accordance with the terms of the Tariff and related agreements.

The Independent Transmission Provider shall be the sole point of Application for all Market Services for Energy, Ancillary Services, and Transmission Service provided in the Independent Transmission Provider's Service Area. Each Market Participant that sells or purchases Energy, including demand side Resources, provides Ancillary Services, or Schedules Transmission Services subject to Transmission Usage Charges in the Independent Transmission Provider Administered Markets, utilizes Market Services and must take service as a Customer under the Tariff.

The Independent Transmission Provider has the right to schedule and dispatch Scheduled Resources and to direct that schedules be changed in an Emergency.

Following the start of the markets, the Independent Transmission Provider shall have the right to file changes to these market rules with the Commission to improve the competitiveness and efficiency of the markets.

3. Informational and Reporting Requirements

The Independent Transmission Provider shall operate and maintain an OASIS that, among other things, will facilitate the posting of Bids to supply Energy, Ancillary Services and Demand Reductions by Suppliers for use by the Independent Transmission Provider and the posting of LMP, clearing prices for Bid-based Ancillary Services, and schedules for accepted Bids for Energy, Ancillary Services and Demand Reductions. The OASIS will be used to post schedules for Bilateral Transactions. The OASIS also will provide historical data regarding market clearing prices for each market in addition to Transmission Usage Charges.

4. Communication Requirements for Market Services

Customers may utilize a variety of communications facilities to access the Independent Transmission Provider's OASIS, including but not limited to, conventional Internet service providers, wide area networks, and dedicated communications circuits. Customers shall arrange for and maintain all communications facilities for the purpose of communication of commercial data to the Independent Transmission Provider. Each Customer shall be the Customer of record for the telecommunications facilities and services it uses and shall assume all duties and responsibilities associated with the procurement, installation and maintenance of the subject equipment and software.

F. Day-Ahead Scheduling and Markets

Preamble

The Independent Transmission Provider will operate a Day-Ahead Market in order to develop a joint Day-Ahead Schedule for Transmission Service, Energy, and Ancillary Services. The Day-Ahead Schedule will be developed so as to maximize the combined economic value of Transmission Service, Energy, and Ancillary Services, based on the Bids submitted.

1. Day-Ahead Scheduling Procedures

1.1 Day-Ahead Trading Deadline: Market Participants may submit Bids for purchase and sale of Energy, Ancillary Services and Transmission, Bilateral Transaction Schedules, Self-Schedules, and Ancillary Services Self-Supply Schedules no later than [to be supplied by Independent Transmission Provider] for use in establishing the Day-Ahead Schedule.

1.2 Rules for Self Schedules

1.2.1 Supplier-Committed Self Schedules

(i) Suppliers of Generation Resources for Energy may Self-Schedule these Resources in the Day-Ahead Markets.

(ii) Self-Schedules by Suppliers of Energy are required only to submit a MW quantity and a location.

1.2.2 Independent Transmission Provider-Committed Self Schedules

(i) Upon request of a Supplier, the Independent Transmission Provider shall develop a schedule for Generation or Demand Resources in which the Schedule optimizes the revenues over the Operating Day for the Resource. These are referred to in this Tariff as Independent Transmission Provider- Committed Self Schedules. This option will typically be used by Energy-Limited Resources, however this option is available to all Generation or Demand Resources.

(ii) Independent Transmission Provider-Committed Self-Schedules are required only to submit a MW quantity and a location.

1.2.3 Self Supply of Ancillary Services

(i) Suppliers of Resources for Regulation and Operating Reserves may Self-Supply these Resources in the Day-Ahead Markets.

(ii) The specific rules for Self-Supply of Regulation and Operating Reserves are in Sections F.4–F.6.

1.3 Rules for Bilateral Transactions Schedules

1.3.1 Internal Transactions

(i) All Internal Transactions must specify a Receipt Point, a Delivery Point, a MW quantity injected at the Receipt Point and a MW quantity withdrawn at the Delivery Point.

(ii) Internal Transactions may also, voluntarily, submit a price Bid ($/MW) over some or all of the MW range. This makes the transaction under the control of the Independent Transmission Provider.

1.3.2 External Transactions

(i) All External Transactions must specify a Receipt Point, a Delivery Point, a MW quantity injected at the Receipt Point and a MW quantity withdrawn at the Delivery Point. Either the Receipt Point or the Delivery Point must be a point at the boundary of the Independent Transmission Provider's Service Area. If the Receipt Point is a boundary point, then the External Transaction is an Import. If the Delivery Point is a boundary point, then the External Transaction is an Export. All External Transactions must specify a minimum run time.

(ii) The Independent Transmission Provider shall offer Market Participants with External Transactions two options for Day-Ahead scheduling. (1) External Transactions can be scheduled without a Price Bid. The Independent Transmission Provider shall take all appropriate steps to accommodate such transactions, such as reservation of ramping capacity. (2) External Transactions can be scheduled in the Day-Ahead Market with a Price Bid ($/MW) over some or all of the MW quantity being scheduled. Transactions with a Bid will only enter the Day-Ahead Schedule if the price is at or below the LMP at the transaction sink node.

(iii) External Transactions will be scheduled on a hourly basis.

1.4 Rules for Bidding: The Independent Transmission Provider shall evaluate all eligible Bids for Energy Supply and Demand, Regulation and Frequency Response, Operating Reserves and Day-Ahead Transmission Service. The requirements for Bid eligibility and the Bid Specifications are in Sections F.2.3, F.3.1, F.4.4, F.5.4 and F.6.4.

1.5 Bid-Based Security Constrained Unit Commitment and Determination of the Day-Ahead Schedule: The Independent Transmission Provider will develop a Security Constrained Unit Commitment schedule over the Operating Day using a computer algorithm that accepts all Self-Schedules and simultaneously maximizes the total value of the Bids, including Virtual Bids, submitted to (i) supply to (incorporating the costs of Start-up, No-load and Incremental Energy) and purchase from the Day-Ahead Market for Energy; (ii) provide sufficient Ancillary Services to support Energy purchased from the Day-Ahead Market; and (iii) receive Transmission Service to support Bilateral Transaction schedules and Self-Schedules submitted Day-Ahead. The Independent Transmission Provider may substitute higher quality Ancillary Services (i.e., shorter response time) for lower quality Ancillary Services when doing so would result in an overall least Bid cost solution.

In developing the Day-Ahead Schedule, the Independent Transmission Provider shall select Suppliers for Energy, Regulation and Frequency Response, and Operating Reserves for each hour of the upcoming day through its Day-Ahead Security-Constrained Unit Commitment, using Bids and/or schedules provided by the Suppliers. The Day-Ahead schedule will include commitment of sufficient Generators and price-sensitive Demand Bids to provide for the safe and reliable operation of the power system operated by the Independent Transmission Provider. The schedule shall honor all operating constraints included in the scheduled Bids. The Day-Ahead schedule shall list the twenty-four (24) hourly injections and withdrawals for: (a) each Customer whose Bid the Independent Transmission Provider accepts for the following Operating Day; and (b) Self-Schedules of Energy, Ancillary Services, and Transmission Service.

1.6 Determination of the Day-Ahead Prices: The Independent Transmission Provider shall calculate the Day-Ahead Energy LMPs and Flowgate LMPs based on a dispatch of committed Generation Resources to meet the Load that has Bid in and been scheduled Day-Ahead. The Day-Ahead Energy LMPs are calculated, according to the Independent Transmission Provider decision, for each Generator bus, load bus, and sets of buses that comprise Zones or Hubs. The Transmission Usage Charge for Bilateral Transactions that are scheduled Day-Ahead is the difference between the Energy LMP for the Delivery Point and the Energy LMP at the Receipt Point. The methodology for calculating the different types of LMPs is described in Sections F.2.4 and 3.3.

The Day-Ahead prices for Ancillary Services will be determined according to procedures described in Sections F.4.5, 5.5, 6.5 and 6.6.

1.7 Load Forecasts: All Load-Serving Entities shall provide their Day-Ahead Load forecasts to the Independent Transmission Provider. The Independent Transmission Provider shall develop an advisory forecast based on these forecasts and its own analysis of next day Load and shall post this forecast.

1.8 Reliability-Based Security Constrained Unit Commitment: In cases in which the sum of all Bilateral Schedules and all Day-Ahead Market purchases to serve Load within the Independent Transmission Provider's Service Area in the Day-Ahead schedule is less than the Independent Transmission Provider's Day-Ahead forecast of Load, the Independent Transmission Provider will commit Resources in addition to the reserves it normally maintains to enable it to respond to contingencies. These additionally-committed Resources are called Replacement Reserves. This commitment of Replacement Reserves will be the result of a Bid-Based Reliability-Based Security Constrained Unit Commitment conducted following the Day-Ahead Security Constrained Unit Commitment. The purpose of this additional commitment of Resources is to ensure that sufficient capacity is available to the Independent Transmission Provider in Real-Time to enable it to meet its Load forecast (including associated Ancillary Services).

In considering which additional Resources to schedule to meet the Independent Transmission Provider's Load forecast, the Independent Transmission Provider will evaluate whether unscheduled Imports can provide additional power at a price within any Bid Price caps set by the Independent Transmission Provider.

The Independent Transmission Provider will develop the Reliability-Based Security Constrained Unit Commitment schedule over the Operating Day using a computer algorithm that minimizes the total cost of committing the additional Generation and Demand Resources that provide Replacement Reserves based solely on the Start-up and No-load Bids of the additionally committed Resources. The Independent Transmission Provider shall use Bids submitted into the Day-Ahead Market. If such Bids are not sufficient to meet the forecast load, the Independent Transmission Provider may solicit additional Bids; these additional Bids will be considered eligible for the Real-Time Market in addition to the Reliability-Based Security Constrained Unit Commitment. Resources committed in the Reliability-Based Security Constrained Unit Commitment are obligated to Start-up and operate at their No-load level.

1.9 Reliability Forecast: In the Security Constrained Unit Commitment program, system operation shall be optimized based on Bids over the Operating Day. However, to preserve system reliability, the Independent Transmission Provider may take steps to ensure that there will be sufficient Resources available to meet forecasted Load and reserve requirements over the day beginning with the next Operating Day, typically completing a one week look ahead.

1.10 Posting the Day-Ahead Schedule: By [a pre-defined deadline to be supplied by Independent Transmission Provider] on the day prior to the Operating Day, the Independent Transmission Provider shall close the Day-Ahead scheduling process and post on its OASIS the Day-Ahead schedule for Energy, Regulation and Frequency Response, and Operating Reserves for each entity that submits a Bid or Self-Schedule. All schedules shall be considered proprietary, with the posting only visible to the appropriate scheduling Customer and Transmission Owners subject to the applicable Code of Conduct. The Independent Transmission Provider will post on the OASIS the aggregate Resources (Day-Ahead Energy, Regulation and Frequency Response and Operating Reserves schedules) and Load (Day-Ahead scheduled and forecast) for each Load bus or Zone, and the Day-Ahead LMP prices (including the Marginal Congestion cost Component and the Marginal Losses component) for each Generation Bus, Load Bus or Load Zone and Hub in each hour of the upcoming Operating Day.

The Independent Transmission Provider shall conduct the Day-Ahead Settlement based upon the Day-Ahead Prices determined in accordance with this Section.

1.11 Day Ahead Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall ensure the minimum recovery of each Resource's Bid prices for Resources scheduled through the Day-Ahead Market or in subsequent commitments for reliability. The is called the Bid Revenue Sufficiency Guarantee.

(i) The Independent Transmission Provider shall determine, on a daily basis, if any Resource committed by the Independent Transmission Provider in the Day-Ahead Market will not recover Start-Up, No Load, and Energy Bid Price through revenues in the Day-Ahead Energy and Ancillary Services markets.

(ii) If the Start-Up and No Load Bids plus the net Energy and Ancillary Services Bid Price over the twenty-four (24) hour day of any Supply Resource exceeds the sum of its Day-Ahead LMP revenue and Ancillary Service revenue over the twenty-four (24) hour day, then that Supplier's Day-Ahead LMP revenue and Ancillary Service revenue shall be augmented by an additional payment, the Supply Bid Revenue Sufficiency Guarantee Payment, in the amount of the shortfall. This payment shall be supported through revenue collected from the Supply Bid Revenue Sufficiency Guarantee Charge.

(iii) If the total Day-Ahead Energy charges to any Demand Resource over the twenty-four (24) hour day exceeds its maximum willingness to pay, as reflected by the difference of its selected Day-Ahead Energy Bids and Start-up Cost Bid, the Demand Resource shall be augmented by a payment, the Demand Bid Revenue Sufficiency Guarantee Payment, in the amount of the overcharge. This payment is supported through revenues collected from the Demand Bid Revenue Sufficiency Guarantee Charge.

2. Day-Ahead Market for Energy

2.1 General: The Day-Ahead Market for Energy establishes clearing prices and settlement rules for Suppliers of Energy that have offered eligible Generation Capacity to the market and for Purchasers of Energy that have chosen not to Self-Supply or procure through bilateral contracts.

2.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (v) for the Day-Ahead Market for Energy. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS rules that are consistent with this Tariff for eligibility to supply Energy in the Day-Ahead Market.

(ii) Establish and post on its OASIS the Bid data requirements and rules and provide the market functions that are consistent with this Tariff required for determination of hourly Day-Ahead LMPs for Energy and selection of Day-Ahead Energy Market Suppliers and Purchasers.

(iii) Establish and post on its OASIS the rules that are consistent with this Tariff for determination of any additional payments necessary to support efficient operations of the Day-Ahead Market for Energy and/or the efficient operation of other Day-Ahead Markets.

(iv) Provide the Settlement functions associated with purchase and sale of Energy in the Day-Ahead Market.

(v) Post the Day-Ahead LMPs for Energy.

2.3 Purchaser Rules and Obligations: Purchasers of Energy in the Day-Ahead Market shall provide the Bid information specified in Sections 2.3.1 to 2.3.3.

2.3.1 Specification of Bids: Purchasers of Day-Ahead Energy must provide the following Bid information. Purchasers must supply all information that is identified as a required Bid component. Purchasers may, but are not required to, submit information that is identified as an optional Bid component.

(i) MW desired to be purchased, with a default value of 0 MW. This is a required Bid component.

(ii) Location (transmission zone, aggregate, or single bus) that the purchaser desires to purchase the designated MWs of power. This is a required Bid component.

(iii) Maximum price ($/MW) at which the purchaser desires to purchase the designated MW of power. (A purchaser may indicate its desire to purchase the designated MWs of power regardless of price, if the purchaser has demonstrated to the Independent Transmission Provider in advance that it is financially capable of paying the highest possible price for the designated MWs.) This is a required Bid component.

(iv) Start-up Cost ($). This Bid component is an additional payment needed by the Purchaser of Energy to curtail its load This is an optional Bid component.

(v) Minimum Curtailment Time (hours). This Bid component is up to a maximum of 24 hours. This is an optional Bid component. If a Minimum Curtailment Time is not indicated, then the default time will be one hour.

(vi) Maximum Curtailment Time (hours). This Bid component is up to a maximum of 24 hours. This is an optional Bid component. If a Maximum Curtailment Time is not indicated, then the default time will be 24 hours.

(vii) Minimum Purchase Time (at least one hour). This is an optional Bid component

(viii) Maximum Purchase Time (hours). This is an optional Bid component.

(ix) Hours that the purchaser desires to purchase the designated MWs of power. This is a required Bid component.

2.3.2 Specification of Virtual Bids: Purchasers of Day-Ahead Virtual Energy must provide Bid components 2.3.1 (i) to (iii). In addition, the Bid shall identify that the Energy purchase is Virtual Energy if the purchase is not backed by actual load.

2.3.3 Period of Bids: The Demand Bids shall be hourly Bids for each hour of the Operating Day in which the price ($) and quantity (MW) components can vary hour by hour.

2.4 Supplier Rules and Obligations

2.4.1 Eligibility to Supply: Suppliers of Day-Ahead Energy shall provide the Bid information specified in Section 2.4.2 . Suppliers of Day-Ahead Virtual Energy shall provide the Bid information specified in 2.4.3- 2.4.4 .

2.4.2 Specification of Bids. Suppliers are required to include the following price, quantity and data components in their Generation Bid. Suppliers must supply all information that is identified as a required Bid component. Suppliers may, but are not required to, submit information that is identified as an optional Bid component. The Bid Data requirements are additional data on Generator characteristics needed by the Independent Transmission Provider for market operations and reliability purposes.

Bid Prices and Quantities

(i) Start-Up ($). This is an optional Bid component (Market Participants can opt to exclude Start-up Costs in their Energy Bid by setting this cost to $0). Limits on the frequency with which Start-up Bid Costs can be changed must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(ii) Minimum Generation (No-load) ($/hour). This is an optional Bid component (Market Participants can opt to exclude No-load Costs in their Energy Bid by setting this cost to $0/hour). Limits on the frequency with which Minimum Generation Bid Costs can be changed must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(iii) Incremental Energy ($/MWh). Market Participants must provide prices for the full MW range of their Operable Capacity, from the Hourly Economic Minimum Level to the

Hourly Economic Maximum Level. This is a required Bid component. [Independent Transmission Provider may add requirements regarding the number of steps or pieces in the Bid function.] The Incremental Energy Bid may be negative, indicating the price that the Supplier is willing to pay for the Generator not to be dispatched below its Hourly Economic Minimum Level. The upper limit on the Bid price of Incremental Energy over the full MW range of the Operable Capacity must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation. Any other limits on the Bid price of Incremental Energy must also be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(iv) Emergency Incremental Energy ($/MWh). Market Participants must provide a price for the Emergency MW range of their Operable Capacity, from the Hourly Economic Maximum Level to the Hourly Emergency Maximum Level. This is a required Bid component. The upper limit on the Bid price of Emergency Incremental Energy must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation. Pricing rules for Emergency uses of Generation Resources are in Section G, 3.7(iii).

Bid Data Requirements

(v) Normal Response Rate (MW/min). The expected response rate for Security Constrained Dispatch. This is a required Bid component.

(vi) Regulation Response Rate (MW/min). The response rate for units providing regulation. This is a required Bid component for Resources offering Regulation service.

(vii) Hourly Economic Minimum Level (MW). This is a required Bid component. Limits on the frequency with which the Hourly Economic Minimum Level can be changed must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(viii) Hourly Economic Maximum Level (MW). This is a required Bid component.

(ix) Hourly Emergency Minimum Level (MW). This is the Minimum Level for a Generator in the event of an Emergency. This is a required Bid component.

(x) Hourly Emergency Maximum Level (MW). This is the Maximum Level for a Generator in the event of an Emergency. This is a required Bid component.

(xi) Start-up Time (hours). The number of hours required to start the Generator. This is a required Bid component.

(xii) Minimum Run Time (hours). This Bid component is up to a maximum of 24 hours. This is a required Bid component. Limits on the Minimum Run Time of particular Generators must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(xiii) Maximum Run Time (hours). This is an optional Bid component.

(xiv) Minimum Down Time (hours). This is an optional Bid component.

(xv) Maximum Start-up Limit or Maximum Shut Down Limit in 24 Hours (integer number). This is an optional Bid component.

(xvi) Location.

2.4.3 Bids to Supply Virtual Incremental Energy

(i) A Virtual Incremental Energy Bid ($/MWh) is an Incremental Energy Bid that specifies that the Bid is a Virtual Transaction, *i.e.,* it is not backed by a physical supply Resource. Virtual Incremental Energy Bids must include (1) a price, (2) a MW quantity, and (3) a location. The upper limit on the Bid price of Virtual Incremental Energy must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

2.4.4 Bids to Supply Decremental Energy

(i) A Decremental Energy Bid ($/MWh) is a Bid to reduce the output of a Generator. Decremental Energy Bids must include (1) a price, (2) a MW quantity, and (3) a location. The upper limit on the Bid price of Decremental Energy must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(ii) A Virtual Decremental Energy Bid ($/MWh) is a Decremental Energy Bid that specifies that the Bid is a Virtual transaction. The upper limit on the Bid price of Virtual Decremental Energy must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation.

(iii) A Decremental Emergency Energy Bid ($/MWh) is a Decremental Energy Bid to reduce the output of a Generator below its Hourly Economic Minimum Level down to its Hourly Emergency Minimum Level. The upper limit on the Bid price of Decremental Emergency Energy must be consistent with the requirements of Part IV, Market Power Monitoring and Mitigation. Pricing rules for Emergency uses of Generation Resources are in Section G, 3.7(iii).

2.4.5 Period of Bids to Supply Energy: A Customer may submit Bids to Supply Incremental Energy or Decremental Energy pursuant to Sections F.2.4.2–2.4.4 that can vary by price ($) and quantity (MW) in each Hour of the Day-Ahead Market.

2.5 Calculation of Day-Ahead Locational Marginal Prices for Energy

The Independent Transmission Provider shall calculate the price of Energy at the Load buses and Generation buses in the Independent Transmission Provider Service Area and at the Interface buses between the Independent Transmission Provider Service Area and adjacent Service Areas on the basis of Energy LMPs. LMPs can be set by Bids to sell or purchase Energy, including External Transaction Imports with Bids, and by transmission Bids. If requested by Market Participants the Independent Transmission Provider will establish Hubs and Zones based on a pre-defined set of buses. The Independent Transmission Provider will calculate load-weighted average Energy LMPs for this pre-defined set of buses, defined as Hub Prices or Zone Prices (or Zonal-LMPs). The Energy LMPs, Hub Prices and Zone Prices shall include separate components for the marginal costs of Congestion and the marginal costs of losses. Energy LMPs determined in accordance with this Section shall be calculated and posted on a Day-Ahead basis for each hour of the Day-Ahead Energy Market by [time to be provided by Independent Transmission Provider].

2.5.1 Energy LMP Calculation: The Independent Transmission Provider will calculate for each bus on its system in each hour the Energy LMP, equal to the marginal cost of making an additional increment of Energy available at the bus in the hour, based on the Bids of sellers and buyers selected in the Day-Ahead Security Constrained unit Commitment for Energy supply and purchase. The Independent Transmission Provider shall designate one bus as the Reference Bus, *r*, for all other buses in the system. The System Marginal Price (SMP_r), is the cost of making an additional increment of Energy available to the Reference Bus, based on Bids selected in the Day-Ahead Security Constrained Unit Commitment for Energy supply and Purchase. For each bus other than the Reference Bus, the Independent Transmission Provider shall determine separate components of the Energy LMP for the marginal costs of Congestion and losses relative to the Reference Bus, consistent with the following equation:

$$\text{Energy LMP}_i = SMP_r + MCC_i + MLC_i,$$

where SMP_r is the system marginal price in each hour at the Reference Bus, *r,* in the system, MCC_i is the LMP component representing the marginal cost of Congestion at bus *i* relative to the Reference Bus, and MLC_i is the LMP component representing the marginal cost of losses at bus *i* relative to the Reference Bus.

(i) Calculation of Marginal Congestion Component: The Independent Transmission Provider will calculate the marginal costs of Congestion at each bus as a component of the bus-level LMP. The Marginal Congestion Component (MCC) component of the Energy LMP at bus *i* is calculated using the equation:

$$MCC_i = -\left(\sum_{k=1}^{K} GSF_{ik} FMP_k\right),$$

where: *K* is the number of thermal or Interface Transmission Constraints; GSF_{ik} is Shift Factor for the Generator at bus *i* on Flowgate *k* which limits flows across that Constraint when an increment of power is injected *i* and an equivalent amount of power is withdrawn at the Reference Bus, and FMP_k is the Flowgate LMP on Flowgate *k* and is equivalent to the reduction in system cost expressed in $/MWh that results from an increase of 1 MW of the capacity on Flowgate k.

(ii) Calculation of Marginal Losses Component: The Independent Transmission Provider will calculate the Marginal Losses Component (MLC) at each Load bus i. The MLC of the LMP at any bus i within the Independent Transmission Provider Service Area is calculated using the equation:

$$MLC_i = (DF_i - 1)\ SMP_i,$$

where DF_i = delivery factor for bus *i* to the system Reference Bus, and $DF_i = (1 - \partial L / \partial G_i)$, where: L is system losses, G_i is generation injection at bus *i,* $\partial L / \partial G_i$ is the partial derivative of system losses with respect to generation injections at bus *i,* that is, the incremental change in system losses associated with an incremental change in the generation injections at bus *i* holding constant other injections and withdrawals at all buses other than the Reference Bus and bus *i*.

2.5.2 Hub Price Calculation: If requested by Market Participants, the Independent Transmission Provider shall calculate a Hub Price based on the Energy LMPs for a set of buses that comprise the Hub. These Hub Prices are the weighted average of the Energy LMPs at the buses that comprise the Hub. The weights will be pre-determined by the Independent Transmission Provider and remain fixed. [The Independent Transmission Provider may add procedures for determining the buses that comprise the Hub and procedures for changing the weights over time.] The Price for Hub *j* can be written as:

$$\text{Hub Price}_j = \sum_{i=1}^{n} \left(W_{Hi} \times \text{LMP}_i \right),$$

where *n* is the number of buses in Hub_j and W_{Hi} is the weighting factor for bus *i* in Hub *j*. The sum of the weighting factors shall add up to 1.

2.5.3 Zone Price Calculation

(i) If requested by Market Participants, the Independent Transmission Provider shall calculate a Zone Price based on the Energy LMPs for a set of buses that comprise the Zone. These Zone Prices are the weighted average of the Energy LMPs at the set of buses that comprise the Zone. The Zone bus weights will equal the fractional share of each load bus in the total load in the Zone in the Hour. [The Independent Transmission Provider may add procedures for determining the buses that comprise the Zone, and assigning weights to those buses, in response to changes in retail load.]

$$\text{Zone Price}_j = \sum_{i=1}^{n} \left(W_{Zi} \times \text{LMP}_i \right),$$

where *n* is the number of Load buses in Zone *j* and W_{Zi} is the load weighting factor for bus *i* in Zone *j*. The sum of the weighting factors adds up to 1.

(ii) If the Zone price is used for Settlement purposes, it is subject to the following rules. (1) Each Zone shall include only the buses of Market Participants who agree to be in the Zone (and thus, who agree that their settlements will be calculated based on the zonal price). Alternatively, any one zone shall include only the buses of a single Market Participant. (2) A Market Participant who wants to be billed at a Zonal Price must include in its Zone all of the buses where Energy deliveries will be billed at the Zonal Price. A Market Participant shall not be allowed to settle Energy purchases at a bus or aggregation of buses if that bus or buses are not included in the Zone.

2.6 Calculation of Additional Payments and Charges

2.6.1 Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall calculate, for each Resource scheduled for Energy in the Day-Ahead Market, the amount of the Bid Revenue Sufficiency Guarantee payment, pursuant to Section F.1.11.

2.6.2 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Day-Ahead Market for Energy.]

2.7 Market Rules for Shortages or Emergencies

(i) [The Independent Transmission Provider may include in this section market rules, including specification of quantities of Energy purchased, calculation of market prices, and determination of out-of-market payments in the event of a shortfall in Energy due to a shortage of available capacity. The market rules shall be in accord with regional or local reliability authority rules and procedures and NERC guidelines.]

(ii) [The Independent Transmission Provider may include in this section procedures for soliciting additional Bids for Energy in the event that Bids and self-scheduled provision of Energy submitted in the Day-Ahead Markets fall short of the Bid-in Load.]

2.8 Settlement

2.8.1 Payments by Purchasers

(i) Each purchaser of Day-Ahead Energy shall be charged for all of its Load scheduled to be served from the Independent Transmission Provider's Day-Ahead Energy Market at the Day-Ahead LMPs applicable to each relevant Load bus and hour.

(ii) If a Market Buyer elects to calculate and settle Energy purchases at Zonal-LMPs, and the Zonal price meets the conditions for settlement specified in Section 2.4(c)(ii), then the market buyer shall be charged for all of its load scheduled to be served from the Day-Ahead Energy Market at the Day-Ahead Zonal-LMPs applicable to each relevant Load Zone and time period.

(iii) On any day when a Market Participant is scheduled to purchase any Energy in the Day-Ahead Market for Energy and/or does not Self-Supply a sufficient amount of its forecasted obligation (based on the Day-Ahead Schedule) for Regulation and Operating Reserves, the Market Participant shall be charged a Day-Ahead Bid Revenue Sufficiency Guarantee Charge. The Market Participant's Day-Ahead Supply Bid Revenue Sufficiency Guarantee Charge on any given day shall equal the product of (i) the Market Participant's total load (in MWh) scheduled in the Day-Ahead Market (which shall equal the sum of the Market Participant's total purchases of Energy in the Day-Ahead Market for Energy plus the Market Participant's total load scheduled to be met from Bilateral Transactions) and (ii) the per unit Day-Ahead Supply Bid Revenue Sufficiency Guarantee Charge.

The per unit Day-Ahead Supply Bid Revenue Sufficiency Guarantee Charge for any given day shall equal (i) the aggregate Bid Revenue Sufficiency Guarantee payments payable to Resources in the Day-Ahead Market for that day, divided by (ii) the sum of the total loads (in MWh) of all Market Participants that are to be charged Day-Ahead Supply Bid Revenue Sufficiency Charges for that day.

2.8.2 Payments to Suppliers

(i) Suppliers of Day-Ahead Energy shall be paid for all Energy scheduled to be delivered in the Day-Ahead Energy Market at the Day-Ahead LMPs applicable to each relevant generation bus.

(ii) The Independent Transmission Provider shall pay Suppliers any additional payments necessary to provide Day-Ahead Energy in accord with efficient market operations, as specified in Section 2.5

2.8.3 Payments by Suppliers

(i) Market Participant's Day-Ahead Demand Bid Revenue Sufficiency Guarantee Charge on any given day shall equal the product of (i) the Market Participant's total quantity (in MWh) scheduled in the Day-Ahead Market (which shall equal the sum of the Market Participant's total sales of Energy in the Day-Ahead Market for Energy plus the Market Participant's total supply scheduled to be met from Bilateral Transactions) and (ii) the per unit Day-Ahead Demand Bid Revenue Sufficiency Guarantee Charge.

The per unit Day-Ahead Demand Bid Revenue Sufficiency Guarantee Charge for any given day shall equal (i) the aggregate Demand Bid Revenue Sufficiency Guarantee payments payable to Resources in the Day-Ahead Market for that day, divided by (ii) the sum of the total supply (in MWh) of all Market Participants that are to be charged Day-Ahead Demand Bid Revenue Sufficiency Guarantee Charges for that day.

3. Day-Ahead Scheduling of Transmission and Settlement Functions for Congestion Revenue Rights

3.1 General: Day-Ahead scheduling of Transmission Service allows Market Participants to obtain Transmission Service to support Bilateral Transactions. This section establishes (1) rules for Bidding and/or scheduling Transmission Service, (2) determining prices (*i.e.*, Transmission Usage Charges, Transmission Usage Charges) for Transmission Service, and (3) settling with Market Participants that are scheduled for Transmission Service in the Day-Ahead Market. The Day-Ahead Energy LMPs shall be used to provide (1) the prices for sales and purchases of Energy and (2) Transmission Usage Charges (Transmission Usage Charges) for Transmission Service to support Bilateral Transactions. Because Transmission Usage Charges are based on the differences between Energy LMPs at the point of injection and point of withdrawal associated with an internal or external Bilateral Transaction, in their schedules requesting Transmission Service, Market Participants have the right to express willingness to pay for the Transmission Usage Charges—or equivalently, for the differences in the Energy LMPs.

In addition, the Day-Ahead Energy LMPs and Flowgate LMPs are used for Settlement of Congestion Revenue Rights. Holders of Receipt Point-to-Delivery Point Congestion Revenue Rights that seek to settle them against Real-Time Energy LMPs can do so by scheduling transactions in the Day-Ahead Energy Market.

3.2 Day-Ahead Transmission Requests

3.2.1 Information Provided by the Customer: Each Customer seeking to be scheduled for Transmission Service in the Day-Ahead Market shall be required to provide the Independent Transmission Provider the information in (i) through (iii) below. In addition, the Customer shall be required to provide the information either in (iv) or (vi), or both. The Customer shall provide this information separately for each transaction involving a different Receipt and/or Delivery Point. The Customer shall have the option of providing the information in (v).

(i) MW to be transmitted;

(ii) The Point of Receipt and the Point of Delivery;

(iii) The hours when the power is to be transmitted;

(iv) The maximum Transmission Usage Charge ($ per MW) that the Customer is willing to pay to receive the Transmission Service. The Customer may indicate that it desires the indicated Transmission Service regardless of the Transmission Usage Charge, if the Customer has demonstrated to the Independent Transmission Provider that it is capable of paying the highest possible Transmission Usage Charge. The Customer may separately indicate the maximum Charge for Marginal Costs of Congestion and the maximum charge for Marginal Losses that it is willing to pay.

(v) The minimum number of consecutive hours that the Customer desires to receive the Transmission Service.

(vi) The maximum total Transmission Usage Charge (in $ per MW) that the Customer is willing to pay to receive Transmission Service over the total number of scheduled hours.

(vii) Whether the Customer desires to provide additional Energy at the receipt point, in an amount that reflects the Marginal Losses associated with the Transmission Service (which the Independent Transmission Provider shall determine at the close of the Day-Ahead Market) in lieu of paying the charge for Marginal Losses.

3.3 Calculation of Day-Ahead Transmission Usage Charges: The Independent Transmission Provider shall charge a Transmission Usage Charge to all Bilateral Transactions whose transmission service was scheduled in the Day-Ahead Market. This charge is the product of (a) the amount of Energy scheduled to be withdrawn by that Customer in each hour in MWh; and (b) the Day-Ahead LMP at the Point of Delivery (which could be a Load Zone in which Energy is scheduled to be withdrawn or the external bus where Energy is scheduled to be withdrawn if Energy is scheduled to be withdrawn at a location outside the Independent Transmission Provider Service Area), minus the Day-Ahead LMP at the Point of Receipt, in $/MWh. The Independent Transmission Provider shall divide each Transmission Usage Charge into separate components for Marginal Costs of Congestion and Marginal Costs of Losses.

3.3.1 Marginal Congestion Component: The Marginal Congestion Component of the Transmission Usage Charge shall be calculated as the Marginal Congestion Component of the Day-Ahead LMP at the Delivery Point minus the Marginal Congestion Component of the Day-Ahead LMP at the Receipt Point, as described in Section F.2.5(i).

3.3.2 Marginal Losses Component: The Marginal Losses Component of the Transmission Usage Charge shall be calculated as the Marginal Losses Component of the Day-Ahead LMP at the Delivery Point minus the Marginal Losses Component of the Day-Ahead LMP at the Receipt Point, as described in Section F.2.5(ii).

3.4 Flowgate LMP Calculation: The Independent Transmission Provider will, in addition to the calculation of the Energy LMPs, calculate Flowgate Locational Marginal Prices (FMPs) on the set of transmission constraints. The calculation for the Flowgate LMP (FMP) for each Transmission Constraint is defined in Section F.2.5.1(i). Independent Transmission Providers that offer Flowgate Rights must also calculate the Day-Ahead Flowgate LMPs (FMPs) on the Transmission Elements designated as Flowgates, based on a weighted average of the Transmission LMPs on the Transmission Elements that comprise the Flowgate:

$$\text{Marginal Price on Flowgate } f = \sum_{k=1}^{m}\left(W_k \times FMP_k\right),$$

where: f is the index of Flowgates; k is a Transmission Element in the set of Flowgates, K; m is the subset of the Transmission Elements that comprise Flowgate f; and W_k are the weights attached to each of the m Transmission Elements that comprise Flowgate f. The sum of the weighting factors adds up to 1. For Flowgates comprised of one Transmission Element, the W_k for that element is equal to 1. The Independent Transmission Provider shall determine the W_k for Transmission elements defined as Flowgates.

3.5 Settlement of Congestion Revenue Rights

3.5.1 Settlement of Receipt Point-to-Delivery Point Congestion Revenue Rights: For each hour in the Day-Ahead Market, the Independent Transmission Provider shall determine the Marginal Congestion Component of each Transmission Usage Charge associated with Transmission Service from a designated Receipt Point to a designated Delivery Point specified in each Receipt Point-to-Delivery Point Congestion Revenue Right (including both Obligation and Option Rights), consistent with Section F.3.3.1. In each instance when the applicable Marginal Congestion Component is positive, the Independent Transmission Provider shall pay to the Primary Holder of the Congestion Revenue Right an amount equal to the applicable hourly Marginal Congestion Component multiplied by the specified MWs. In each instance when the applicable Marginal Congestion Component is negative, the Independent Transmission Provider shall charge to each Primary Holder of an Obligation Right (but not the Primary Holder of an Option Right) an amount equal to the absolute value of the applicable Marginal Congestion Component multiplied by the specified MWs.

3.5.2 Settlement of Flowgate Rights: For each hour in the Day-Ahead Market, the Independent Transmission Provider shall determine, consistent with the provisions in Section F.3.4, the Flowgate LMP in each direction associated with each Flowgate on the transmission system operated by the Independent Transmission Provider.

(i) Holders of Flowgate Rights. For each hour of the Day-Ahead Market, the Independent Transmission Provider shall pay each Primary Holder of a Flowgate Right an amount equal to the applicable hourly Flowgate LMP multiplied by the MWs specified in the Primary Holder's Flowgate Right.

3.6 Disposition of Congestion Revenue Surplus or Deficit

3.6.1 Hourly Congestion Charge Collection: The Hourly Congestion Charge Collection is defined here as the sum of the Hourly Energy Congestion Charge Collection plus the Hourly Transmission Congestion Charge Collection. The Hourly Energy Congestion Charge Collection is defined for any hour of the Day-Ahead Market as (i) the net amounts charged to purchasers of Energy in the Independent Transmission Provider's Day-Ahead Market associated with the Marginal Congestion Component of the hourly LMPs at the purchasers' buses, less (ii) the net amounts paid to sellers of Energy in the Independent Transmission Provider's Day-Ahead Market associated with the Marginal Congestion Component of the hourly LMPs at the sellers' buses. The Hourly Transmission Congestion Charge Collection is defined for any hour of the Day-Ahead Market as the net amounts charged to Customers for Transmission Service scheduled in the Day-Ahead Market associated with the Marginal Congestion Component of the applicable hourly Transmission Usage Charges.

3.6.2 Hourly Net Congestion Revenue Owed to Congestion Revenue Rights Holders: The Hourly Net Congestion Revenue owed to Congestion Revenue Rights Holders for any hour in the Day-Ahead Market is defined here as the net hourly amounts payable to Primary Congestion Revenue Rights Holders pursuant to Sections F.3.5.1 and F.3.5.2.

3.6.3 Determination and Disposition of Congestion Revenue Surplus or Deficit: For each hour of the Day-Ahead Market, the Independent Transmission Provider shall calculate the Hourly Congestion Charge Collection and the Hourly Net Congestion Revenue Owed to Congestion Revenue Rights

Holders. For each hour of the Day-Ahead Market where the Hourly Congestion Charge Collection exceeds the Hourly Net Congestion Revenue Owned to Congestion Revenue Rights Holders, the Independent Transmission Provider shall allocate the revenue surplus to the Transmission Owners. For each hour of the Day-Ahead Market where the Hourly Congestion Charge Collection is less than the Hourly Net Congestion Revenue Owned to Congestion Revenue Rights Holders, the Independent Transmission Provider shall charge the revenue deficit to the Transmission Owners.

3.7 Disposition of Marginal Loss Revenue Surplus

3.7.1 Hourly Marginal Loss Charge Collection: The Hourly Marginal Loss Charge Collection is defined here as the sum of the Hourly Energy Marginal Loss Charge Collection plus the Hourly Transmission Marginal Loss Charge Collection. The Hourly Energy Marginal Loss Charge Collection is defined for any hour of the Day-Ahead Market as (i) the net amounts charged to purchasers of Energy in the Independent Transmission Provider's Day-Ahead Market associated with the Marginal Losses Component of the hourly LMPs at the purchasers' buses, less (ii) the net amounts paid to sellers of Energy in the Independent Transmission Provider's Day-Ahead Market associated with the Marginal Losses Component of the hourly LMPs at the sellers' buses. The Hourly Transmission Marginal Loss Charge Collection is defined for any hour of the Day-Ahead Market as the net amounts charged to Customers for Transmission Service scheduled in the Day-Ahead Market associated with the Marginal Cost Component of the applicable hourly Transmission Usage Charges.

3.7.2 Determination and Disposition of Marginal Loss Revenue Surplus: For each hour of the Day-Ahead Market, the Independent Transmission Provider shall calculate the Hourly Marginal Loss Charge Collection and the Hourly Net Energy Revenue Owed to Generators for losses associated with all Transactions. For each hour of the Day-Ahead Market where the Hourly Marginal Loss Charge Collection exceeds the Hourly Net Energy Revenue Owed to Generators for Losses associated with all Transactions, the Independent Transmission Provider shall allocate the revenue surplus to reduction in the charge for Network Access Service. [The Independent Transmission Provider shall determine the exact allocation to each Customer and will file procedures for determining the allocation of the revenue surplus to each Customer.]

4. Day-Ahead Market for Regulation and Frequency Response

4.1 General: The Day-Ahead Market for Regulation establishes clearing prices and settlement rules for Suppliers that have offered eligible Regulation capacity to the market. The Transmission Provider shall procure Regulation through this market on behalf of Load-Serving Entities that have chosen not to Self-supply or purchase through bilateral contracts. Both Generation and Load may Bid to provide Regulation in the Day-Ahead Market if they meet the criteria for eligibility.

4.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (vii) for the Day-Ahead Market for Regulation. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS Regulation criteria and requirements in accord with regional or local reliability authority rules and NERC guidelines.

(ii) Establish and post on its OASIS a Total Regulation Requirement for the Independent Transmission Provider's Service Area for each hour of the Operating Day. This hourly requirement enters the Day-Ahead Security Constrained Unit Commitment. The Total Regulation Requirement may be subdivided into locational Regulation Requirements; that is, those assigned to specific locations (or Zones) within the Service Area.

(iii) Allocate the obligation for meeting the Total Regulation Requirement among Load-Serving Entities. The obligation of each Load-Serving Entity in any hour shall be equal to the product of (1) the Load-Serving Entity's Real-Time load in the hour as a percentage of the total Real-Time load in the Independent Transmission Provider's Service Area in the hour and (2) the total Day-Ahead Total Regulation Requirement for the hour. The Load-Serving entity's forecasted Regulation obligation for purposes of Section F.2.8.1(iii) shall be equal to the product of (1) the Load-Serving Entity's Day-Ahead scheduled load in an hour and (2) the total Day-Ahead Regulation requirement in the hour.

(iv) Establish and post on its OASIS rules for eligibility to supply Regulation in the Day-Ahead Market that are consistent with this Tariff, including minimum technical requirements and performance standards for a Generator or Load to provide Regulation in response to signals sent by the Independent Transmission Provider.

(v) Establish and post on its OASIS the Bid data requirements and rules for self-scheduling and Bidding, and provide the market functions required for determination of hourly Day-Ahead Spinning Regulation Market Clearing Prices and selection of Day-Ahead Regulation Market Suppliers. Establish and post on its OASIS how these pricing and selection rules are modified to account for locational Regulation requirements. Establish how these pricing and selection rules are modified in the event of shortages in Bid-in Regulation capacity. [The Independent Transmission Provider shall include procedures for self-supply.]

(vi) Establish and post on its OASIS the rules for determination of any additional payments necessary to support efficient operations of the Day-Ahead Regulation Market and the efficient joint operation of the Day-Ahead Market for Regulation and other Day-Ahead Markets.

(vi) Provide the Settlement functions associated with purchase and sale of Regulation in the Day-Ahead Market.

(vii) Post the Day-Ahead Regulation Market Clearing Prices.

4.3 Purchaser Rules and Obligations: The Purchaser of Regulation Service has the obligations and rights set forth in (i) through (iv):

(i) Each Load-Serving Entity is required to fulfill its Operating Day Regulation obligation on the basis of either or both Self-Supply or procurement from the Day-Ahead and Real-Time markets for Regulation. The Transmission Provider shall procure Regulation Reserve on behalf of Load-Serving Entities and determine the final cost of each MW purchased.

(ii) A Load-Serving entity may meet its Regulation obligation through Self-Supply by offering into the Day-Ahead Market for Regulation its own Resources capable of supplying Regulation or Resources for which it has made contractual arrangements with third parties able to provide Regulation on a comparable basis. Such self-supplied Resources must be placed under the Independent Transmission Provider's control, and must meet the Independent Transmission Provider's rules for eligibility to supply Regulation (see Section 5.2 and 5.4.1). These self-supplied Resources are scheduled in the Day-Ahead Market for Regulation at a Supply Bid Price of $0/MWh. Also, a Load-Serving Entity shall be paid the applicable Day-Ahead Market Clearing Price for any Regulation self-supplied in excess of its obligation.

(iii) A Load-Serving Entity that has not fulfilled all of its Regulation obligation through Self-Supply is required to allow the Independent Transmission Provider to procure sufficient Regulation that it has not self-supplied through the Day-Ahead, and if necessary, the Real-Time Regulation Market to fulfill the obligation that is not self-supplied.

4.4 Supplier Rules and Obligations

4.4.1 Eligibility to Supply: To be eligible to supply Regulation in the Day-Ahead Market for Regulation, a Supplier or a Generator contracted by a Supplier must meet criteria (i) to (v), as follow.

(i) Suppliers of Regulation may use only Generators and/or Load that are electrically within the Independent Transmission Provider's Service Area.

(ii) Suppliers of Regulation may use only Generators and/or Load that are able to respond to AGC Base Point Signals sent by the Independent Transmission Provider pursuant to the Independent Transmission Provider procedures.

(iii) Suppliers of Regulation may use only Generators and/or Load that meet Independent Transmission Provider standards for Generator or Load performance.

(iv) Suppliers of Regulation shall not use, contract to provide, or otherwise commit the capability that is designated to provide Regulation to provide Energy or Spinning Reserve to any party other than the Independent Transmission Provider.

(v) Suppliers of Regulation shall provide the Bid information specified in Section F.4.4.2.

4.4.2 Specification of Bids: Suppliers of Regulation must provide the Bid information in (i) to (vii), as follows.

(i) Availability Bid price ($/MWh).

(ii) Regulation Capability (MW) of the Generator supplying Regulation.

(iii) Response Rate (MW/Minute) of the Generator supplying Regulation.

(iv) Upper and Lower Regulation Limits (MW).

(v) Hours of availability to provide Regulation.

(vi) Any additional physical data required by the Independent Transmission Provider

(vii) Location of Resources

4.5 Calculation of Market Clearing Price: The Independent Transmission Provider shall calculate a Market Clearing Price for the Day Ahead Market for Regulation, using the following methodology.

The Independent Transmission Provider shall establish a Supplier Regulation Price for each Supplier based on the sum of the Supplier's Availability Bid and its Day-Ahead Unit-Specific Opportunity Cost (as defined below). The hourly Day-Ahead Regulation Market Clearing Price shall be the higher of (i) the highest Supplier Regulation Price needed to meet the Independent Transmission Provider's Regulation Requirement for each hour of the Next Day, or (ii) the highest Market Clearing Price in the hour for Operating Reserves.

The Unit-Specific Opportunity Costs of a Resource Bidding to sell Regulation each hour shall be equal to the product of:

(i) the deviation of the Regulation set point of the Generator that is required in order to provide Regulation from the Resource's expected output level if it had been scheduled or dispatched in economic merit order to provide Energy, times

(ii) the greater of (a) the $/MWh difference between the expected Energy LMP at the generation bus for the Resource and the Bid price for Energy from the Resource (at the megawatt level of the Regulation set point for the Resource) in the Real-Time Energy Market and (b) zero.

4.6 Calculation of Additional Payments and Charges

4.6.1 Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall calculate for each Resource scheduled for Regulation in the Day-Ahead Market the amount of the Bid Revenue Sufficiency Guarantee payment, pursuant to Section F.1.11.

4.6.2 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Day-Ahead Market for Regulation.]

4.7 Market Rules for Shortages

(i) [The Independent Transmission Provider may include in this section market rules, including calculation of market prices and determination of out of market payments, in the event of a shortfall in Regulation in the Day-Ahead Market due to a shortage of available capacity. The market rules shall be in accord with regional or local reliability authority rules and procedures and NERC guidelines.]

(ii) [The Independent Transmission Provider may include in this section procedures for soliciting additional Bids for Regulation in the event that Bids and self-supplied provision of Regulation submitted in the Day-Ahead Markets fall short of the Regulation Requirement for the Operating Day.

4.8 Settlement: The Independent Transmission Provider will provide timely settlement of sales of Regulation in the Day-Ahead Market for Regulation pursuant to Section 4.8.1.

4.8.1 Payments to Suppliers

(i) The Independent Transmission Provider shall pay each Supplier, the hourly Day-Ahead Market Clearing Price for Regulation times the Quantity (MW) of the Supplier's Regulation scheduled (*i.e.*, selected) in the hour.

5. Day-Ahead Market for Operating Reserve—Spinning Reserve

5.1 General: The Independent Transmission Provider shall establish bid-based markets for the types of Operating Reserve—Spinning Reserves (*e.g.*, 10-minute, 30-minute) necessary to meet local reliability authority rules or NERC guidelines. Day-Ahead Markets for Spinning Reserve shall be used to provide clearing prices and settlement rules for Suppliers of Spinning Reserve that have offered eligible Spinning Reserve capacity to the market. The Transmission Provider shall procure Spinning Reserves in this market on behalf of Purchasers of Spinning Reserve that have chosen not to self-supply or procure through bilateral contracts. Both Generation and Load may Bid to provide Spinning Reserve in the Day-Ahead Market if they meet criteria for eligibility.

5.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (vii) for the Day-Ahead Market for Spinning Reserve. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS Spinning Reserve criteria and requirements in accord with regional or local reliability authority rules and NERC guidelines.

(ii) Establish and post on its OASIS a Total Spinning Reserve Requirement for the Independent Transmission Provider's Service Area for each hour of the Operating Day. This hourly requirement enters the Day-Ahead Security Constrained Unit Commitment. The Total Spinning Reserve Requirement may be sub-divided into locational Spinning Reserve Requirements; that is, assigned to specific locations (or Zones) within the Service Area.

(iii) Allocate the obligation for meeting the Total Spinning Reserve Requirement among Load-Serving Entities. The obligation of each Load-Serving Entity in any hour shall be equal to the product of (1) the Load-Serving Entity's Real-Time load in the hour as a percentage of the total Real-Time load in the Independent Transmission Provider's Service Area in the hour and (2) the total Day-Ahead Total Spinning Reserve Requirement for the hour. The Load-Serving Entity's forecasted Spinning Requirement obligation for purposes of Section F.2.8.1(iii) shall be equal to (1) the Load-Serving Entity's Day-Ahead scheduled load in an hour multiplied by (2) the total Day-Ahead Spinning Reserve requirement in the hour.

(iv) Establish and post on its OASIS rules for eligibility to supply Spinning Reserve in the Day-Ahead Market that are consistent with this Tariff, including minimum technical requirements and performance standards for a Generator or Load to provide Spinning Reserve.

(v) Establish and post on its OASIS the Bid data requirements and rules for self-scheduling and Bidding that are consistent with this Tariff, and provide the market functions required for determination of hourly Day-Ahead Spinning Reserve Market Clearing Prices and selection of Day-Ahead Spinning Reserve Market Suppliers. Establish how these pricing and selection rules are modified to account for locational Spinning Reserve requirements. Establish how these pricing and selection rules are modified in the event of shortages in Bid-in Spinning Reserve capacity.

(vi) Establish and post on its OASIS the rules for determination of any additional payments necessary to support efficient operations of the Day-Ahead Market for Spinning Reserve and the efficient joint operation of the Day-Ahead Market for Spinning Reserve and other Day-Ahead Markets.

(vii) Provide the Settlement functions associated with sale of Spinning Reserve in the Day-Ahead Market.

(vii) Post the Day-Ahead Market Clearing Prices for Spinning Reserve.

5.3 Purchaser Rules and Obligations

(i) Each Load-Serving Entity is required to fulfill its Operating Day Spinning Reserve obligation on the basis of either or both self-supply or procurement from the Day-Ahead and Real-Time markets for Spinning Reserve. The Independent Transmission Provider shall procure Spinning Reserve on behalf of Load-Serving Entities and determine the final cost of each MW purchased.

(ii) A Load-Serving Entity may meets its Spinning Reserve obligation through Self-Supply by offering its own Resources capable of supplying Spinning Reserves or Resources for which it has made contractual arrangements with third parties able to provide Spinning Reserves on a comparable basis. Such self-supplied Resources must be placed under the Independent Transmission Provider's control, and must meet the Independent Transmission Provider's rules for eligibility (see Section 5.2 and 5.4.1). These self-supplied Resources are scheduled in the Day-Ahead Spinning Reserves Market. A Load-Serving Entity shall be paid the applicable Day-Ahead Market clearing price for any Spinning Reserve self-supplied in excess of its obligation.

(iii) A Load-Serving Entity that has not fulfilled all of its Spinning Reserve obligation through Self-Supply is required to allow the Independent Transmission Provider to procure sufficient Spinning Reserve that it has not Self-Supplied through the Day-Ahead and, if necessary, Real-Time Spinning Reserve market to fulfill the obligation that is not Self-Supplied.

5.4 Supplier Rules and Obligations

5.4.1 Eligibility to Supply: To be eligible to supply Spinning Reserve in the Day-Ahead Market for Spinning Reserve, a Supplier or a Generator contracted by a Supplier must meet criteria (i) to (iv), as follow.

(i) Suppliers of Spinning Reserve may use only Generators and/or Load that are electrically within the Independent Transmission Provider's Service Area.

(ii) Suppliers of Spinning Reserve may use only Generators and/or Load that meet Independent Transmission Provider standards for Generator performance; similarly, Demand Resources must meet Independent Transmission Provider standards for response capability.

(iii) Suppliers of Spinning Reserve shall not use, contract to provide, or otherwise commit the capability that is designated to provide Spinning Reserve to provide Energy, Regulation or Supplemental Reserve to any party other than the Independent Transmission Provider.

(iv) Suppliers of Spinning Reserve shall provide the Bid information specified in Section 5.4.2.

5.4.2 Specification of Bids: Suppliers of Spinning Reserve must provide the Bid information in (i) to (vi), as follows.

(i) Availability Bid price ($/MWh).

(ii) Response Rate (MW/Minute) of the Generator supplying Spinning Reserve.

(iii) Hours of availability to provide Spinning Reserve.

(iv) Any additional physical data required by the Independent Transmission Provider.

(v) Location of Resource.

5.5 Calculation of Market Clearing Price

5.5.1 Methodology for Calculation of Clearing Price: The Independent Transmission Provider shall calculate a Market Clearing Price for the Day Ahead Market for Spinning Reserve, using the following methodology.

The Independent Transmission Provider shall establish a Supplier Spinning Reserve Price for each Supplier based on the sum of the Supplier's Availability Bid and its Day-Ahead Unit-Specific Opportunity Cost (as defined below). The hourly Day-Ahead Spinning Reserve Market Clearing Price shall be the higher of (i) the highest Supplier Spinning Reserve Price needed to meet the Independent Transmission Provider's Spinning Reserve Requirement for each hour of the Next Day, or (ii) the highest Market Clearing Price in the hour for Supplemental Reserves.

The Unit-Specific Opportunity Costs of a Resource Bidding to sell Spinning Reserve each hour shall be equal to the product of:

(i) the deviation of the set point (MWh) of the Generator that is required in order to provide Spinning Reserve from the Resource's output level if it had been scheduled or dispatched in economic merit order to provide Energy, times

(ii) the greater of (a) the $/MWh difference between the Energy LMP at the generation bus for the Resource and the Bid price for Energy from the Resource (at the megawatt level of the Spinning Reserve set point for the Resource) in the Day-Ahead Energy Market and (b) zero.

5.5.2 Calculation of Zonal or Locational Prices: Separate Day-Ahead Spinning Reserve Market Clearing Prices will be calculated for Spinning Reserve located in each distinct Reserve Location for which there is a separate Spinning Reserve requirement. When there are no binding transmission constraints between Reserve Locations, the Day-Ahead Ancillary Price for Spinning Reserve shall be the same in each of the locations.

5.5.3 Transmission for Operating Reserves: A Supplier located outside of a particular Reserve Location may provide Spinning Reserves if the necessary transmission arrangements to deliver Energy from the Supplier's capacity to the Reserve Location are made. The cost of any transmission service would have to be included in evaluating the total cost of Operating Reserves.

5.6 Calculation of Additional Payments and Charges

5.6.1 Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall calculate, for each Resource scheduled for Spinning Reserve in the Day-Ahead Market the amount of the Bid Revenue Sufficiency Guarantee payment, pursuant to Section F.1.11.

5.6.2 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Day-Ahead Markets for Spinning Reserves.]

5.7 Market Rules for Shortages

(i) [The Independent Transmission Provider may include in this section market rules, including specification of quantities, calculation of market prices, and determination of out of market payments in the event of a shortfall in the required system requirements for Spinning Reserves due to a shortage of available capacity. The market rules shall be in accord with regional or local reliability authority rules and procedures and NERC guidelines.]

(ii) [The Independent Transmission Provider may include in this section procedures for soliciting additional Bids for Spinning Reserves in the event that Bids and self-supplied provision of Spinning Reserves submitted in the Day-Ahead Markets fall short of the required system requirements for Spinning Reserves.]

5.8 Settlement: The Independent Transmission Provider will provide timely settlement of purchases and sales of Spinning Reserve in the Day-Ahead Market for Spinning Reserve pursuant to Sections 5.8.1.

5.8.1 Payments to Suppliers

(i) The Independent Transmission Provider shall pay each Supplier the hourly Day-Ahead Spinning Reserve Market Clearing Price times the quantity (MW) of the Supplier's Spinning Reserve capability provided in the hour.

6. Day-Ahead Markets for Operating Reserve-Supplemental Reserve

6.1 General: The Independent Transmission Provider shall establish the types of Supplemental Reserves (*e.g.*, 10-minute, 30-minute, 60-minute) necessary to meet local reliability authority rules and NERC guidelines. Day-Ahead Markets for Supplemental Reserves establish clearing prices and settlement rules for Suppliers of Supplemental that have offered eligible Supplemental Reserve capacity to the market. The Transmission Provider shall procure Supplemental Reserves in this market on behalf of Purchasers of Supplemental Reserves that have chosen not to Self-supply or procure through bilateral contracts. Both Generation and Load may Bid to provide Supplemental Reserves in the Day-Ahead Market if they meet criteria for eligibility.

6.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (viii) for the Day-Ahead Markets for Supplemental Reserves. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS Supplemental Reserve criteria and requirements in accord with regional or local reliability authority rules and NERC guidelines.

(ii) Establish and post on its OASIS Total Supplemental Reserves Requirements for the Independent Transmission Provider's Service Area for each Hour of the Operating Day. This hourly requirement enters the Day-Ahead Security Constrained Unit Commitment. The Total Supplemental Reserve Requirements may be subdivided into locational Supplemental Reserve Requirements; that is, assigned to specific locations (or zones) within the Service Area.

(iii) Allocate the obligation for meeting the Total Supplemental Reserve Requirement among Load-Serving Entities. The obligation of each Load-Serving Entity in any hour shall be equal to the product of (1) the Load-Serving Entity's Real-Time load in the hour as a percentage of the total Real-Time load in the Independent Transmission Provider's Service Area in the hour and (2) the Total Day-Ahead Total Supplemental Reserve Requirement for the hour. The Load-Serving Entity's forecasted Supplemental Reserve obligation for purposes of Section F.2.8.1 (iii) shall be equal to the product of (1) the Load-Serving Entity's Day-Ahead scheduled load in the hour as a percent of the total Day-Ahead load in the Independent Transmission Provider's Service Area in the hour and (2) the Total Day-Ahead Supplemental Reserve Requirement in the hour.

(iv) Establish and post on its OASIS rules for eligibility to supply Supplemental Reserves in the Day-Ahead Market that are consistent with this Tariff, including minimum technical requirements and performance standards for a Generator and/or Load to provide Supplemental Reserves.

(v) Establish and post on its OASIS the Bid data requirements and rules for self-scheduling and Bidding that are consistent with this Tariff, and provide the market functions required for determination of hourly Day-Ahead Supplemental Reserves Market Clearing Prices and selection of Day-Ahead Supplemental Reserves Market Suppliers. Establish how these pricing and selection rules are modified to account for locational Supplemental Reserves requirements. Establish how these pricing and selection rules are modified in the event of a shortage of Bid-in Supplemental Reserve capacity.

(vi) Provide the Settlement functions associated with purchase and sale of Supplemental Reserves in the Day-Ahead Market.

(vii) Post the Day-Ahead Supplemental Reserves Market Clearing Prices.

6.3 Purchaser Rules and Obligations:

(i) Each Load-Serving Entity is required to fulfill its Operating Day Supplemental Reserves obligation on the basis of either or both Self-Supply or procurement from the Day-Ahead and Real-Time markets for Supplemental Reserves. The Independent Transmission Provider shall procure Supplemental Reserve on behalf of Load-Serving Entities and determine the final cost of each MW purchased.

(ii) A Load-Serving Entity may meet its Supplemental Reserve obligation through Self-Supply by offering into the Day-Ahead Market for Supplemental Reserves its own Resources capable of supplying Supplemental Reserves or Resources for which it has made contractual arrangements with third parties able to provide Supplemental Reserves on a comparable basis. Such self-supplied Resources must be placed under the Independent Transmission Provider's control, and must meet the Independent Transmission Provider's rules for eligibility (see Sections 6.2 and 6.4.1). These self-supplied Resources are scheduled in the Day-Ahead Reserves Market. A Load-Serving Entity shall be paid the applicable Day-Ahead Market clearing price for any Supplemental Reserve self-supplied in excess of its obligation.

(iii) A Load-Serving Entity that has not fulfilled all of its Supplemental Reserves obligation through self-supply is required to allow the Independent Transmission Provider to procure sufficient Supplemental Reserves that it has not Self-Supplied through the Day-Ahead and, if necessary, Real-Time Supplemental Reserves market to fulfill the obligation that is not Self-Supplied.

6.4 Supplier Rules and Obligations

6.4.1 Eligibility to Supply: To be eligible to supply Supplemental Reserves in the Day-Ahead Markets for Supplemental Reserve, a Supplier or a Generator contracted by a Supplier must meet criteria (i) to (iv), as follow.

(i) Subject to Independent Transmission Provider requirements, Suppliers of Supplemental Reserves may use Generators and/or Load that are electrically within or outside the Independent Transmission Provider's Service Area.

(ii) Suppliers of Supplemental Reserves may use only Generators and/or Load that meet Independent Transmission Provider standards for Generator performance.

(iii) Suppliers of Supplemental Reserves shall not use, contract to provide, or otherwise commit the capability that is designated to provide Supplemental Reserves to provide Energy, Regulation and Frequency Response, or Spinning Reserve to any party other than the Independent Transmission Provider.

(iv) Suppliers of Supplemental Reserves shall provide the Bid information specified in Section 4.2.

6.4.2 Specification of Bids: Suppliers of Supplemental Reserves must provide the Bid information in (i) to (iv), as follows.

(i) Availability Bid price ($/MWh).

(ii) Response Rate (MW/Minute) of the Resource supplying Supplemental Reserve.

(iii) Hours of availability to provide Supplemental Reserve.

(iv) Any additional physical data required by the Independent Transmission Provider.

(v) Location of Resource.

6.5 Calculation of Market Clearing Prices for Supplemental Reserves

6.5.1 Methodology for Calculation of Prices: The Independent Transmission Provider shall calculate a Market Clearing Price for each Day-Ahead Market for Supplemental Reserves, using the following methodology.

The Independent Transmission Provider shall establish a Supplier Estimated Supplemental Reserve Price for each Supplier based on the sum of the Supplier's Availability Bid and its Day-Ahead Unit-Specific Opportunity Cost (as defined below). The hourly Day-Ahead Supplemental Reserve Market Clearing Price shall be the higher of (i) the highest Supplier Supplemental Reserve Price needed to meet the Independent Transmission Provider's Supplemental Reserve Requirement for each hour of the Next Day, or (ii) the Market Clearing Price in the hour for a lower quality Supplemental Reserve.

The Unit-Specific Opportunity Costs of a Resource Bidding to sell Supplemental Reserves each hour shall be equal to the product of:

(i) the deviation of the set point (MWh) of the Generator that is expected to be required in order to provide Supplemental Reserve from the Resource's output level if it had been scheduled or dispatched in economic merit order to provide Energy, times

(ii) the absolute value of the difference between the Energy LMP at the generation bus for the Resource and the Bid price for Energy from the Resource (at the megawatt level of the Supplemental Reserve set point for the Resource) in the Day-Ahead Energy Market.

6.5.2 Calculation of Zonal or Locational Prices: Separate Day-Ahead Supplemental Reserve Market Clearing Prices will be calculated for Supplemental Reserve located in each distinct Reserve Location for which there is a separate Supplemental Reserve requirement. When there are no binding transmission constraints between Reserve Locations, the Day-Ahead Ancillary Price for Supplemental Reserve shall be the same in each of the locations.

6.5.3 Transmission for Operating Reserves: A Supplier located outside of a particular Reserve Location may provide 10-Minute Supplemental Reserve if the necessary arrangements Energy from the Supplier's capacity to the Reserve Location are made. The cost of any transmission service would have to be included in evaluating the total cost of Operating Reserves.

6.6 Calculation of Additional Payments and Charges

6.6.1 Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall calculate, for each Resource scheduled for Supplemental Reserves in the Day-Ahead Market the amount of the Bid Revenue Sufficiency Guarantee payment, pursuant to Section F.1.11.

6.6.2 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Day-Ahead Markets for Supplemental Reserves.]

6.7 Market Rules for Shortages

(i) [The Independent Transmission Provider may include in this section market rules, including specification of quantities of Supplemental Reserve purchased, calculation of market prices, and determination of out-of-market payments in the event of a shortfall in the required system requirements for Supplemental Reserves due to a shortage of available capacity. The market rules shall be in accord with regional or local reliability authority rules and procedures and NERC guidelines.]

(ii) [The Independent Transmission Provider may include in this section procedures for soliciting additional Bids for Supplemental Reserves in the event that Bids and self-supplied provision of Supplemental Reserves submitted in the Day-Ahead Markets fall short of the required system requirements for Supplemental Reserves.]

6.8 Settlement: The Independent Transmission Provider will provide timely settlement of sales of Supplemental Reserves in the Day-Ahead Markets for Supplemental Reserves pursuant to Sections 6.8.1.

6.8.1 Payments to Suppliers

(i) The Independent Transmission Provider shall pay each Supplier the hourly Day-Ahead Supplemental Reserve Market Clearing Price times the quantity (MW) of the Supplier's Supplemental Reserve capability provided in the hour.

G. Post-Day-Ahead Scheduling and Real-Time Markets

Preamble

The Independent Transmission Provider will operate a Real-Time Market in order to develop a post Day-Ahead Schedule and Real Time Dispatch Schedule for Transmission Service, Energy, and Ancillary Services. The Real-Time Schedule will be developed so as to maximize the combined economic value of transmission service, Energy, and Ancillary Services, based on the Bids submitted.

1. Post-Day-Ahead Bidding and Scheduling Procedures

1.1 General: The Independent Transmission Provider shall establish procedures for modification of the Day-Ahead Schedule and development of the Real-Time Schedule and dispatch that incorporate components (i) to (vi), as follow.

(i) The Independent Transmission Provider will allow Market Participants that have had selected in the Day-Ahead Schedule (1) a Quantity of Energy, whether a purchase or sale, Regulation or Operating Reserve, (2) a Bilateral Transaction, or (3) a Self-Schedule or Self-Supply, to change the Quantities in the Schedule at any time following the close of the Day-Ahead Market but before the [Scheduling Deadline to be provided by the Independent Transmission Provider] prior to each Dispatch Hour in the Operating Day.

(ii) The Independent Transmission Provider will allow Suppliers or Purchasers of Energy and Suppliers of Regulation or

Operating Reserves that have capacity not selected in the Day-Ahead Schedule to submit new Bids, including Prices ($/MW) and Quantities (MW), into the Real-Time Market. [Independent Transmission Provider will provide schedule.]

(iii) The Independent Transmission Provider will allow Market Participants to submit new Bilateral Transactions and Self-Schedules at any time following the close of the Day-Ahead Market but before the [Scheduling Deadline to be provided by the Independent Transmission Provider] prior to each Dispatch Hour in the Operating Day.

(iv) The Independent Transmission Provider will post on its OASIS the Deadlines for Scheduling Revised or New Quantities and for submission of Price Bids into the Real-Time Market, consistent with the Tariff.

(v) The Independent Transmission Provider shall establish scheduling procedures for External Transactions during each Hour and Quarter-Hour of the Operating Day, consistent with the requirements established by the Commission.

(vi) A Supplier or Purchaser in the Real-Time Market, as well as a Bilateral Schedule or Self-Schedule that submits a Price Bid, that follows Independent Transmission Provider Dispatch Instructions that deviate from the previously selected schedules submitted by the Supplier or Purchaser in the Day-Ahead Market, shall be provided with a Bid Revenue Sufficiency Guarantee, pursuant to Section G.2.3.

1.2 Rules for Self Schedules

1.2.1 Supplier-Committed Self Schedules

(i) Suppliers that wish to increase the amount of Energy scheduled above the amounts scheduled in the Day-Ahead Market, regardless of the applicable Real-Time Energy LMP, may so inform the Independent Transmission Provider [before the scheduling deadline provided by the Independent Transmission Provider] prior to each Dispatch Hour in the Operating Day.

(ii) Such Suppliers of Energy are required to submit a MW quantity and a location.

1.3 Rules for Bilateral Transactions

1.3.1 Internal Transactions

(i) All Internal Transactions submitted or modified after the Day-Ahead Schedule must specify a Receipt Point, a Delivery Point, a MW quantity injected at the Receipt Point and a MW quantity withdrawn at the Delivery Point.

(ii) Internal Transactions may voluntarily submit a Price Bid ($/MW) over some or all of the MW range which indicates the Customer's willingness to reduce or eliminate the Transaction in the next Security Constrained Dispatch time period at the Independent Transmission Provider's instruction when the applicable Real-Time Transmission Usage Charge reaches or exceeds the price Bid.

(iii) Internal Transactions may voluntarily submit a Decremental Energy Bid (in $/MW) over some or all of the MW range, which indicates the Customer's willingness to reduce the amount of Energy supplied at the Receipt Point at the Independent Transmission Provider's instruction (while retaining the amount of Energy withdrawn at the Delivery Point) when the Real-Time Energy LMP at the Receipt Point falls below the Decremental Energy Bid.

1.3.2 External Transactions

(i) All External Transactions submitted or modified after the Day-Ahead Schedule must specify a Receipt Point, a Delivery Point, a MW quantity injected at the Receipt Point and a MW quantity withdrawn at the Delivery Point. Either the Receipt Point or the Delivery Point must be a point at the boundary of the Independent Transmission Provider Service Area. All External Transactions must specify a minimum run time.

(ii) The Independent Transmission Provider shall offer Market Participants with External Transactions submitted after the Day-Ahead Schedule or modifying the Day-Ahead Schedule two options for scheduling. (1) External Transactions can be scheduled without a Price Bid. (2) External Transactions can be scheduled with a Price Bid ($/MW) over some or all of the MW quantity being scheduled.

(iii) External Transactions that are Exports may voluntarily submit a Decremental Energy Bid (in $/MW) over some or all of the MW range, which indicates the Customer's willingness to reduce the amount of Energy supplied at the Receipt Point at the Independent Transmission Provider's instruction (while retaining the amount of Energy withdrawn at the Delivery Point) when the Real-Time Energy LMP at the Receipt Point falls below the Decremental Energy Bid. External Transactions that are imports may voluntarily submit an Incremental Energy Bid (in $/MW) over some or all of the MW range, which indicates the Customer's willingness to reduce the amount of Energy withdrawn at the Delivery Point at the Independent Transmission Provider's instruction (while retaining the amount of Energy injected at the Receipt Point) when the Real-Time Energy LMP at the Delivery Point rises above the Incremental Energy Bid.

(iv) The Independent Transmission Provider will adjust External Transactions schedules on quarter hour notice.

(v) The Independent Transmission Provider shall accept Short Notice External Transactions (SNETs) following the Real-Time Trading Deadline up to some later SNET Deadline set by the Independent Transmission Provider. SNETs are not eligible to set Real-Time LMPs. SNETs have the lowest priority in the event of Curtailment of Customers.

1.4 Rules for Bidding: The Independent Transmission Provider shall evaluate accept all eligible Bids for Energy Supply and Demand, Regulation, and Operating Reserves. The requirements for Bid eligibility and the Bid Specifications are in Sections G 3.4, G.5.4 and G.7.4.

2. Security Constrained Intra-Day Unit Commitment and Dispatch

2.1 Intra-Day Security Constrained Unit Commitment: The Independent Transmission Provider may undertake a periodic intra-day Security-Constrained Unit Commitment for Resources with Start-up and No-load costs not committed in the Day-Ahead Schedule.

2.2 Security Constrained Dispatch: The Independent Transmission Provider shall run a Security Constrained Dispatch every five minutes to minimize the total Bid Production Costs of meeting the system Load and maintaining scheduled interchanges with adjacent Service Areas over the next Security Constrained Dispatch Interval. Bid Production Costs, for this purpose, will be calculated using selected Day-Ahead and Real-Time Bids for Energy and Ancillary Services submitted into the Real-Time Market. The Independent Transmission Provider shall dispatch the Power System consistent with the Bids that are submitted by Suppliers and accepted by the Independent Transmission Provider, while satisfying the actual system Load.

2.3 Intra-Day Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall ensure the minimum recovery of each Reserve's Bid prices for Resources scheduled after the close of the Day-Ahead Market, committed on an intra-day basis, or dispatched through the Real-Time Market.

(i) The Independent Transmission Provider shall determine, on a daily basis, if any Resource committed by the Independent Transmission Provider in the Real-Time Market will not recover its Start-Up, No Load and Energy Bid Price through revenues in the Real-Time Energy and Ancillary Services markets.

(ii) If the Start-Up and No Load Bids plus the net Energy and Ancillary Services Bid Price over the twenty-four (24) hour day of any Supply Resource scheduled, committed, or dispatched by the Independent Transmission Provider exceeds its Real-Time LMP revenue and Ancillary Service Revenue over the twenty-four (24) hour day, then that Supplier's Real-Time LMP revenue, the Real-Time Supply Bid Revenue Sufficiency Guarantee payment, shall be augmented by an additional payment in the amount of the shortfall. Resources not scheduled, committed, or dispatched by the Independent Transmission Provider, but which continue to operate shall not receive such a payment. This payment shall be supported through revenue collected from the Supply Bid Revenue Sufficiency Guarantee Charge.

(iii) If the total Real-Time Energy charges to any Demand Resource over the twenty-four (24) hour day exceeds its maximum willingness to pay, as reflected by the difference of its Real-Time Energy Bids and Start-up Cost Bid, the Demand Resource shall be augmented by a payment, the Demand Bid Revenue Sufficiency Guarantee Payment, in the amount of the overcharge. This payment is supported through revenues collected from the Demand Bid Revenue Sufficiency Guarantee Charge.

3. Real-Time Market for Energy

3.1 General: The Real-Time Market for Energy establishes clearing prices and settlement rules for Suppliers of Energy that have offered eligible Energy capacity to the market and for Purchasers of Energy that have chosen not to self-supply or procure through bilateral contracts.

3.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligations to provide services (i) to (v) for the Real-Time Market for

Energy. The rules governing these services are contained in this section.

(i) Establish and post on its OASIS rules that are consistent with this Tariff for eligibility to supply Energy in the Real-Time Market.

(ii) Establish and post on its OASIS the Bid data requirements and rules that are consistent with this Tariff and provide the market functions required for determination of hourly Real-Time Energy Market Clearing Prices and selection of Real-Time Energy Market Suppliers.

(iii) Establish and post on its OASIS the rules that are consistent with this Tariff for determination of any Additional Payments necessary to support efficient operations of the Real-Time Energy Market and/or the efficient operation of other Real-Time Markets.

(iv) Provide the Settlement functions associated with purchase and sale of Energy in the Real-Time Market.

(v) Post the Real-Time LMPs for Energy.

3.3 Purchaser Rules and Obligations

3.3.1 Specification of Bids. Bids to Purchase Energy in the Real-Time Market for Energy shall have the same price, quantity and data requirements as Bids to Purchase Energy in the Day-Ahead Market for Energy, as set forth in Section F.2.3.1. Virtual Demand Bids are not permitted in the Real-Time Market.

3.4 Supplier Rules and Obligations

3.4.1 Eligibility to Supply

(i) Suppliers of Real-Time Energy may not re-submit capacity selected for Energy in the Day-Ahead Market. Suppliers of Real-Time Energy may lower the Bid Price of capacity not selected for Energy in the Day-Ahead Market.

(ii) Suppliers of Real-Time Energy shall provide the Bid information specified in Section F.2.4.2.

3.4.2 Specification of Bids: Bids to Supply Energy in the Real-Time Energy Market, including Incremental and Decremental Energy, have the same price, quantity and data requirements as Bids to Supply Energy in the Day-Ahead Market for Energy, as set forth in Sections F.2.3 (b)–(d). Virtual Supply Bids are not permitted in the Real-Time Market.

3.4.3 Period of Bids to Supply Energy: Bids to Supply Incremental Energy or Decremental Energy pursuant to Sections F.3.4.1–3.4.2 can vary by price ($) and quantity (MW) in each Hour of the Real-Time Market.

3.5 Calculation of Real-Time Locational Marginal Prices for Energy

(i) Immediately in advance of each Security Constrained Dispatch Interval, the Independent Transmission Provider shall post the Real-Time Energy LMPs for each bus on its system that it estimates will clear the market and match Generation with Load during the upcoming Security Constrained Dispatch Interval, based on the Real-Time Bids submitted. These estimated Energy LMPs shall be called Ex Ante LMPs. The pricing calculations for each of these LMPs should be the same as those for the Day-Ahead Market, as set forth in Section F.2.4, with the modifications contained in this Section G.3.5.

(ii) Power system operations in the Real-Time Market, including, but not limited to, the determination of the least costly means of serving Load, depend upon the availability of a complete and consistent representation of Generator outputs, Loads, and power flows on the network. In calculating LMPs, the Independent Transmission Provider shall obtain a complete and consistent description of conditions on the electric network by using the most recent power flow solution produced by the Independent Transmission Provider's dispatch software and/or software that measures actual system conditions in Real-Time, such as a State Estimator.

3.5.1 Ex Post Energy LMP Calculation: At the close of each Security Constrained Dispatch Interval, the Independent Transmission Provider shall calculate Energy LMPs for each bus on its system that shall be used for settlement of the Real-Time Market. These LMPs shall be called Ex Post Energy LMPs. The Ex Post Energy LMP for a Security Constrained Dispatch Interval at a given bus shall be equal to the lower of (a) the Ex Ante Energy LMP for that bus; and (b) the marginal cost of making available to the bus the Energy actually produced during the Security Constrained Dispatch Interval by suppliers that submitted Real-Time Energy Bids.

3.5.2 Determination of Energy LMPs by Fixed Block Resources: In calculating LMPs in the Day-Ahead Market, the Bid of any Fixed Block Unit (*i.e.,* a unit whose output cannot be adjusted in increments as small as 1 MW) will not be considered in calculating the Day-Ahead LMP at any bus. In calculating LMPs in the Real-Time Market, the price Bid of a Fixed Block Unit may set LMP, but only when some portion of its Energy is necessary to meet Load, displace higher cost Energy, or satisfy Operating Reserves Requirements. The marginal cost of a Fixed Block Unit that forces more economic units to be backed down will not set Real-Time LMP unless needed to meet Load, displace higher price Energy or meet Reserves requirements. The marginal cost of a Fixed Block Unit will not set Real-Time LMP at any other time, including those times when it is scheduled solely to meet its minimum runtime requirements or because of inflexibilities in its operation.

3.5.3 Five Minute Real-Time LMPs: During the Operating Day, the LMP calculation shall be performed every [five minutes, or some other minute by minute interval determined by the system technology and software], using the Independent Transmission Provider's LMP methodology, producing a set of Real-Time Prices based on system conditions during the preceding interval.

3.6 Calculation of Additional Payments and Charges

3.6.1 Bid Revenue Sufficiency Guarantee: The Independent Transmission Provider shall calculate, for each Resource scheduled, committed or dispatched for Energy in the Real-Time Market, the amount of the Bid Revenue Sufficiency Guarantee payment, pursuant to Section G.2.3.

3.6.2 Undergeneration by Suppliers

(i) [The Independent Transmission Provider may file to establish pricing rules, including market-based penalties, for Suppliers of Energy that persistently provide less Energy in Real-Time than instructed. One market-based penalty is to require the Supplier to buy Regulation at the Real-Time Market Clearing Price for Regulation in a quantity equivalent to the Energy not provided.]

(ii) [Exemptions: If the Independent Transmission Provider proposes penalties, suppliers, such as intermittants, that have constraints on following Dispatch Instructions or other operating limitations should be exempt from these penalties.]

(iii) Replacement Reserve Penalty [The Transmission Provider may file to establish market-based penalties for Suppliers of Regulation that provide less Regulation in Real-Time than instructed.]

3.6.3 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Real-Time Markets for Energy.]

3.7 Market Rules for Shortages or Emergencies

(i) [The Independent Transmission Provider may include in this section market rules, including calculation of market prices and determination of out-of-market payments, in the event of a shortfall in Energy in the Real-Time Market due to a shortage of available capacity or an Emergency. The market rules shall be in accord with regional or local reliability authority rules and procedures and NERC guidelines.]

(ii) After the Day-Ahead Schedule is published, and up to a pre-specified period prior to each Dispatch Hour, the Independent Transmission Provider may, after giving notice to affected Resources, in order to prevent or address an Emergency, raise their Bid-in upper operating limits to their maximum and make the additional capacity available to the Scheduling for the Real-Time Market.

(iii) In the event of Emergency, Incremental Energy purchased above a Generator's Hourly Economic Maximum Level and up to the Generator's Hourly Emergency Maximum Level will be settled at the Real-Time LMPs. Decremental Energy purchased below the Hourly Economic Minimum Level and up to the Hourly Emergency Minimum Level will be settled at the higher of (1) the Bid Price for the Decremental Emergency Energy and (2) Real-Time LMPs.

3.8 Settlement: The Independent Transmission Provider will provide timely settlement of purchases and sales of Energy in the Real-Time Market for Energy pursuant to Sections G.3.7.1 and G.3.7.2.

3.8.1 Settlement when Actual Energy Injections are Less than Scheduled Energy Injections: When the actual Energy injections from a Supplier over a Security Constrained Dispatch Interval are less than its Energy scheduled in the Day-Ahead Market to be injected over that SCE interval, the Supplier shall pay for the difference in a charge equal to the product of: (a) the Real-Time Energy LMP calculated for that Security Constrained Dispatch Interval at the applicable Supplier's bus; and (b) the difference between the scheduled Energy injections and the actual Energy injections at that bus.

3.8.2 Settlement when Actual Energy Injections are Greater than Scheduled Energy Injections: When the actual Energy injections from a Supplier over a Security Constrained Dispatch Interval are greater than the Energy scheduled in the Day-Ahead Market to be injected over that Security Constrained Dispatch Interval, the Supplier shall be paid for the difference in a payment equal to the product of: (a) the Real-Time Energy LMP calculated for that Security Constrained Dispatch Interval at the applicable Supplier's bus; and (b) the difference between the actual Energy injections and the scheduled Energy injections at that bus.

3.8.3 Settlement when Actual Energy Withdrawals are Less than Scheduled Energy Withdrawals: When a Customer's actual Energy withdrawals over a Security Constrained Dispatch Interval are less than its Energy withdrawals scheduled in the Day-Ahead Market over that Security Constrained Dispatch Interval, the Customer shall be paid the product of: (a) the Real-Time Energy LMP calculated for that Security Constrained Dispatch Interval at the applicable Customer's bus (or at the Customer's zone, if the Customer elects to calculate and settle Energy purchases at Zonal-LMPs and meets the conditions specified in Section F.2.4(c)(ii)); and (b) the difference between the scheduled Energy withdrawals and the actual Energy withdrawals at that bus.

3.8.4 Settlement when Actual Energy Withdrawals are Greater than Scheduled Energy Withdrawals: When a Customer's actual Energy withdrawals over a Security Constrained Dispatch Interval are greater than its Energy withdrawals scheduled in the Day-Ahead Market over that Security Constrained Dispatch Interval, the Customer shall pay for the difference in a charge equal to the product of: (a) The Real-Time Energy LMP calculated for that Security Constrained Dispatch Interval at the applicable Customer's bus (or at the Customer's zone, if the Customer elects to calculate and settle Energy purchases at Zonal-LMPs and meets the conditions specified in Section F.2.4(c)(ii)); and (b) the difference between the actual Energy withdrawals and the scheduled Energy withdrawals at that bus.

4. Real-Time Scheduling for Transmission

4.1 General: As in the Day-Ahead Market, Real-Time Energy LMPs serve dual functions, providing (1) the prices for sales and purchases of Energy and (2) market-based prices for Congestion Management, including Congestion Charges to Bilateral Transactions, and Marginal Losses.

4.2 Transmission Bids: Customers may submit Bilateral Transaction Schedules that indicate whether or not they are willing to pay the Marginal Congestion Charge component of the Transmission Usage Charge. If the Bid indicates that the Customer is not willing to pay Congestion Charges, then the Bilateral Transaction will be scheduled only if there is no Marginal Congestion Charge in the Real-Time Market. If the Bid indicates that the Customer is willing to pay Congestion Charges, then the Bilateral Transaction will be scheduled regardless of the Marginal Congestion Charge in the Real-Time Market.

4.3 Real-Time Transmission Usage Charges

The Independent Transmission Provider shall charge a Transmission Usage Charge to all Bilateral Transactions whose transmission service was scheduled after the determination of the Day-Ahead schedule, or who schedule additional transmission service after the determination of the Day-Ahead schedule. This charge is the product of (a) the amount of Energy scheduled (as of pre-determined trading deadline) to be withdrawn by that Customer in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Customer in that hour, in MWh; and (b) the Real-Time LMP at the Point of Delivery (which could be a Load Zone in which Energy is scheduled to be withdrawn or the external bus where Energy is scheduled to be withdrawn if Energy is scheduled to be withdrawn at a location outside the Independent Transmission Provider Service Area), minus the Real-Time LMP at the Point of Receipt, in \$/MWh. The Independent Transmission Provider shall divide each Transmission Usage Charge into separate components for Marginal Costs of Congestion and Marginal Costs of Losses.

4.3.1 Marginal Congestion Component: The Marginal Congestion Component of the Transmission Usage Charge shall be calculated as the Marginal Congestion Component of the Real-Time LMP at the Delivery Point minus the Marginal Congestion Component of the Real-Time LMP at the Receipt Point, as described in Section F.2.5(i).

4.3.2 Marginal Losses Component: The Marginal Losses Component of the Transmission Usage Charge shall be calculated as the Marginal Losses Component of the Real-Time LMP at the Delivery Point minus the Marginal Losses Component of the Real-Time LMP at the Receipt Point, as described in Section F.2.5(ii).

4.4 Calculation of Flowgate LMPs: The Independent Transmission Provider shall calculate and post Ex-Post Flowgate LMPs for the Real-Time Market.

4.5 Marginal Loss Charge Collection: The Real-Time Marginal Loss Charge Collection for any SCD interval is defined here as the sum of the Real-Time Energy Marginal Loss Charge Collection plus the Real-Time Transmission Marginal Loss Charge Collection for that SCD interval. The Real-Time Energy Marginal Loss Charge Collection is defined for any SCD interval of the Real-Time Market as (i) the sum of the net amounts associated with the Marginal Loss Component of the applicable Real-Time Energy LMP charged to: (a) each Supplier whose actual Energy injections over the SCD interval are less than its Energy scheduled in the Day-Ahead Market to be injected over that SCD interval and (b) each Purchaser whose actual Energy withdrawals over the SCD interval exceed its Energy scheduled in the Day-Ahead Market to be withdrawn over that SCD interval; less: (ii) the sum of the net amounts associated with the Marginal Loss Component of the applicable Real-Time Energy LMP paid to (c) each Supplier whose actual Energy injections over the SCD interval exceed its Energy scheduled in the Day-Ahead Market to be injected over that SCD interval and (d) each Purchaser whose actual Energy withdrawals over the SCD interval are less than its Energy scheduled in the Day-Ahead Market to be withdrawn over that SCD interval. The Real-Time Transmission Marginal Loss Charge Collection for any SCD interval is defined for any SCD interval of the Real-Time Market as the net amounts charged to Customers for Transmission Service scheduled in the Real-Time Market for the SCD interval associated with the Marginal Cost Component of the applicable hourly Transmission Usage Charges; less the net amounts associated with the Marginal Cost Component of the applicable hourly Transmission Usage Charges paid to Customers for Transmission Service scheduled in the Day-Ahead Market for reductions in Transmission Service in the Real-Time Market during the SCD interval.

4.5.1 Determination and Disposition of Marginal Loss Revenue Surplus: For each SCD interval of the Real-Time Market, the Independent Transmission Provider shall calculate the Marginal Loss Charge Collection and the Net Energy Revenue Owed to Generators for Losses associated with all Transactions. For each SCD interval of the Real-Time Market where the Marginal Loss Charge Collection exceeds the Net Energy Revenue Owed to Generators for Losses associated with all Transactions, the Independent Transmission Provider shall allocate the revenue surplus to reduction in the charge for Network Access Service. [The Independent Transmission Provider shall determine the exact allocation to each Customer and will file procedures for determining the allocation of the revenue surplus to each Customer.]

4.6 Disposition of Other Real-Time Revenue Surplus or Deficit: The Independent Transmission Provider shall calculate, for each Operating Day, the interval of the Real-Time Market, and the net revenue surplus or deficit from the operation of the Real-Time Market (defined as the difference between the revenues collected from all sources and all payment made to all sources, excluding the surplus for losses calculated pursuant to Section G.4.5). The Independent Transmission Provider shall allocate the revenue surplus or deficit for the Operating Day to the Transmission Owners. [The Independent Transmission Provider shall file procedures for determining the allocation of the surplus or deficit to Transmission Owners.]

5. Real-Time Market for Regulation

5.1 General: The Transmission Provider may require additional Regulation capability in response to system conditions in the Operating Day. The Real-Time Market for Regulation establishes clearing prices and settlement rules for eligible Suppliers of Regulation that have offered Regulation capacity following the close of the Day-Ahead Market. The Transmission Provider shall procure Regulation in this market on behalf of Purchasers who choose not to Self-supply or purchase through bilateral contracts. Both Generation and Load may to provide Regulation in the Real-Time Market if they meet criteria for eligibility.

5.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (viii) for the Real-Time Market for Regulation. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS criteria and requirements in accord with local reliability authority rules and NERC guidelines such that there is sufficient provision of Regulation in the Real-Time Dispatch.

(ii) Establish and post on its OASIS rules for eligibility to supply Regulation in the Real-Time Market.

(iii) Provide Base Point Signals to Generators providing Regulation to direct the Generator's output.

(iv) Establish and post on its OASIS the Bid data requirements and rules and provide the market functions required for determination of hourly Real-Time Regulation Market Clearing Prices and selection of Real-Time Regulation Market Suppliers. Establish how the pricing rules and selection procedures will be modified in the event of a shortage of Regulation capacity during the Operating Day.

(v) Monitor the Suppliers' performance to ensure that they provide Regulation Service as required.

(vi) Establish and post on its OASIS the rules for determination of any Additional Payments necessary to support efficient operations of the Real-Time Regulation Market and/or the efficient operation of other Real-Time Markets.

(vii) Provide the Settlement functions associated with purchase and sale of Regulation in the Real-Time Market.

(viii) Post the Real-Time Regulation Market Clearing Prices.

5.3 Purchaser Rules and Obligations

(i) Market Participants with a Regulation Requirement may fulfill their requirement by (1) self-scheduling an eligible Generator or Demand-Side Resource, (2) a bilateral contract with an eligible Supplier, or (3) purchasing from the Regulation Market.

(ii) Self-suppliers and purchasers of Regulation through Bilateral Contract must provide data on location and physical capabilities of the Generator or Supplier providing Regulation (see Section 4.2).

5.4 Supplier Rules and Obligations

5.4.1 Eligibility to Supply

(i) Suppliers of Regulation may only use Generators and/or Load that are electrically within the Independent Transmission Provider's Service Area.

(ii) Suppliers of Regulation may only use Generators and/or Load that are able to respond to AGC Base Point Signals sent by the Independent Transmission Provider pursuant to the Independent Transmission Provider Procedures.

(iii) Suppliers of Regulation may only use Generators and/or Load that meet Independent Transmission Provider standards for Generator performance.

(iv) Suppliers of Regulation shall not use, contract to provide, or otherwise commit the capability that is designated to provide Regulation to provide Energy or Spinning Reserve to any party other than the Independent Transmission Provider.

(v) Suppliers of Regulation shall provide the Bid information specified in Section 4.2.

(vi) Suppliers of Real-Time Regulation may not re-submit capacity selected for Energy in the Day-Ahead Market. Suppliers of Real-Time Regulation may lower the Bid Price of capacity selected for Energy in the Day-Ahead Market.

5.4.2 Specification of Bids

Suppliers of Regulation must provide the following Bid information:

(i) Availability Bid price ($/MWh).

(ii) Regulation Capability (MW) of the Generator supplying Regulation.

(iii) Response Rate (MW/Minute) of the Generator supplying Regulation.

(iv) Upper and Lower Regulation Limits (MW).

(v) Hours of availability to provide Regulation.

(vi) Any additional physical data required by the Independent Transmission Provider.

5.4.3 Bidding and Scheduling Process

(i) Bids rejected by the Independent Transmission Provider in the Day-Ahead Market may be modified and resubmitted into the Real-Time Market by the Supplier to the Independent Transmission Provider. [The Independent Transmission Provider Tariff will provide Procedures].

(ii) Bids in the Day-Ahead Market that are not accepted by the Independent Transmission Provider shall be automatically considered for the Real-Time Market, unless withdrawn by the Supplier.

(iii) If a Supplier reduces its available MW subsequent to being scheduled to provide Regulation or Operating Reserves (either Day-Ahead or in a Supplemental Commitment), and if it, as a result, can no longer provide both the amount of Energy it was scheduled to provide Day-Ahead and the amount of Regulation and Operating Reserves it was scheduled to provide, the Independent Transmission Provider will first reduce the amount of Operating Reserves it is scheduled to provide, and then will reduce the amount of Regulation it is scheduled to provide, until the total amount of Energy, Regulation and Operating Reserves it is scheduled to provide is equal to its available MW (or until it is no longer scheduled to provide Regulation or Operating Reserves).

5.5 Calculation of Market Clearing Price: The Independent Transmission Provider shall calculate a Market Clearing Price for the Real-Time Market for Regulation, using the following methodology.

The Independent Transmission Provider shall establish a Supplier Regulation Price for each Supplier based on the sum of the Supplier's Availability Bid and its Real-Time Unit-Specific Opportunity Cost (as defined below). The Real-Time Regulation Market Clearing Price shall be the higher of (i) the highest Supplier Regulation Price needed to meet the Independent Transmission Provider's Regulation Requirement for each Dispatch Interval, or (ii) the highest Market Clearing Price in Dispatch Interval for Spinning Reserves or Supplemental Reserves.

The Unit-Specific Opportunity Costs of a Resource for bidding to sell Regulation shall be equal to the product of:

(i) the deviation of the Regulation set point of the Generator that is required to provide Regulation from the Resource's output level if it had been scheduled or dispatched in economic merit order to provide Energy, times

(ii) the greater of (a) the $/MWh difference between the Real-Time Energy LMP at the generation bus for the Resource and the Real-Time Bid price for Energy from the Resource (at the megawatt level of the Regulation set point for the Resource) in the Real-Time Energy Market or (b) zero.

5.6 Calculation of Additional Payments and Charges

5.6.1 Bid Revenue Sufficiency Guarantee: Resources scheduled for Regulation in the Real-Time Market are eligible for the Bid Revenue Sufficiency Guarantee, pursuant to Section G.2.3.

5.6.2 Failure to Provide Regulation in Real-Time: The Independent Transmission Provider shall, if a Resource providing Regulation Service trips off line, immediately attempt to re-establish a supply for the remainder of that Resource's commitment. Any additional cost incurred by the Independent Transmission Provider as a result of covering the defaulting Resource's remaining commitment shall be reimbursed to the Independent Transmission Provider by the defaulting Supplier. If the Availability payment for the replacement Regulation Service decreases, the Independent Transmission Provider shall not pay the defaulting Supplier the difference in cost.

5.6.3 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Real-Time Markets for Regulation.]

5.7 Market Rules for Shortages or Emergencies

(i) [The Independent Transmission Provider may include in this section market rules, including specification of quantities and calculation of prices, in the event of a shortfall in the required system requirements for Regulation in the Real-Time Market. The market rules shall be in accord with regional or local reliability authority rules and procedures and NERC guidelines.]

5.8 Settlement: The Independent Transmission Provider will provide timely settlement of purchases and sales of Regulation in the Real-Time Market for Regulation pursuant to Sections 5.8.1and 5.8.2.

5.8.1 Payments by Purchasers

(i) The Independent Transmission Provider shall calculate the total obligation for Regulation for each Load-Serving Entity for each hour of the Operating Day. The total hourly obligation for each Load-Serving Entity in an Operating Day shall equal the product of (a) the total Regulation requirement for the Independent Transmission Provider's Service Area for the hour of the Operating Day and (b) the ratio of (1) the Load-Serving Entity's total actual Load in the hour to (2) the total actual Load in the Independent Transmission Provider's Service Area in the hour of the of the Operating Day. The net obligation for Regulation of a Load-Serving Entity in an hour of the Operating Day shall be equal to the greater of (a) the Load-Serving Entity's total obligation minus the amount of Regulation that it has Self-Supplied in the Day-Ahead Market or (b) zero.

(ii) For each hour of the Operating Day, each Load-Serving Entity shall be charged an amount equal to the product of (1) the aggregate net amount paid by the Independent Transmission Provider in the Day-Ahead and Real-Time Markets to procure Regulation for the hour, and (2) the ratio of (a) the Load-Serving Entity's net obligation for Regulation in the hour to (b) the sum of the net obligations for Regulation of all Load-Serving Entities in the Independent Transmission Provider's Service Area in the hour.

5.8.2 Payments to Suppliers

(i) The Independent Transmission Provider shall pay Suppliers the Real-Time Regulation Market Clearing Price times the quantity (MW) of Regulation capability.

(ii) The Independent Transmission Provider shall pay Suppliers any Additional Payments necessary to provide Real-Time Regulation in accord with efficient market operations.

5.9 Monitoring Suppliers and Generators

(i) The Independent Transmission Provider may establish:

(1) Resource performance measurement criteria;

(2) Procedures to disqualify Suppliers using Resources that consistently fail to meet such criteria; and

(3) Procedures to re-qualify disqualified Suppliers, which may include a requirement to first demonstrate acceptable performance for a time.

(ii) The Independent Transmission Provider shall establish and implement a Performance Tracking System to monitor the performance of Resources that provide Regulation Service.

(iii) Payments by the Independent Transmission Provider to each Supplier of Regulation Service may be based on the Resource's performance with respect to the performance indices. Suppliers that fail to perform at a level consistent with these indices may forfeit all or a substantial portion of their Availability payments, which would otherwise be payable for the subject hour. Suppliers that consistently fail to perform adequately may be disqualified by the Independent Transmission Provider, pursuant to Independent Transmission Provider Procedures. [The Independent Transmission Provider would include such procedures in this section.]

6. Real-Time Market for Operating Reserve—Spinning Reserve

6.1 General: The Transmission Provider may require additional Spinning Reserves capability in response to system conditions in the Operating Day. The Real-Time Market for Spinning Reserve establishes clearing prices and settlement rules for eligible Suppliers of Spinning Reserve that have offered Spinning Reserve capacity to the market. The Transmission Provider shall procure Regulation in this market on behalf of Purchasers who choose not to Self-supply or purchase through Bilateral Contracts. Both Generation and Load may Bid to provide Spinning Reserve in the Real-Time Market if they meet criteria for eligibility.

6.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (viii) for the Real-Time Market for Spinning Reserve. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS Spinning Reserve criteria and requirements in accord with local reliability authority rules and NERC guidelines.

(ii) Establish and post on its OASIS rules for eligibility to supply Spinning Reserve in the Real-Time Market.

(iii) Establish and post on its OASIS minimum technical requirements and performance standards for a Generator and/or Load to provide Spinning Reserve.

(iv) Establish and post on its OASIS the Bid data requirements and rules and provide the market functions required for determination of hourly Real-Time Spinning Reserve Market Clearing Prices and selection of Real-Time Spinning Reserve Market Suppliers. It shall make this selection with the objective of minimizing the cost of meeting Load and providing all necessary Ancillary Services in that hour. Establish how the pricing rules and selection procedures will be modified in the event of a shortage of Spinning Reserve capacity during the Operating Day.

(v) Establish and post on its OASIS the rules for determination of any Additional Payments necessary to support efficient operations of the Real-Time Spinning Reserve Market and/or the efficient operation of other Real-Time Markets.

(vi) Provide the Settlement functions associated with purchase and sale of Spinning Reserve in the Real-Time Market.

(vii) Post the Real-Time Spinning Reserve Market Clearing Prices.

6.3 Purchaser Rules and Obligations

6.3.1 Market Participants with a Spinning Reserve Requirement may fulfill their requirement by

(i)(1) self-supplying an eligible Generator or Demand-Side Resource; (2) a bilateral contract with an eligible Supplier; or (3) purchasing from the Spinning Reserve Market.

(ii) Self-suppliers and purchasers of Spinning Reserve through Bilateral Contract must provide data on location and physical capabilities of the Generator or Supplier providing Spinning Reserve (see Section 4.2)

6.4 Supplier Rules and Obligations: Suppliers whose Generators or demand side Resources have not been scheduled to provide Spinning Reserve and which still have Capacity that is synchronized with the grid and has not been committed for use in any other way may submit Bids to provide Spinning Reserve to the Independent Transmission Provider.

6.4.1 Eligibility to Supply

(i) Suppliers of Spinning Reserve may only use Generators and/or Load that are electrically within the Independent Transmission Provider's Service Area.

(ii) Suppliers of Spinning Reserve may only use Generators and/or Load that meet Independent Transmission Provider standards for Generator performance.

(iii) Suppliers may not contract to provide, or otherwise commit any Capacity from a Generator that has been scheduled to operate or to provide Operating Reserves, in either the Day-Ahead commitment or any supplemental commitment conducted by the Independent Transmission Provider.

(iv) Suppliers of Spinning Reserve shall not use, contract to provide, or otherwise commit the capability that is designated to provide Spinning Reserve to provide Energy, Regulation or Supplemental Reserve to any party other than the Independent Transmission Provider. Suppliers may enter into alternate sales arrangements utilizing any capacity that has not been scheduled to operate or to provide Operating Reserves.

(v) Suppliers of Spinning Reserve shall provide the Bid information specified in Section 4.2.

(vi) Suppliers may not increase the Energy Bids made for the portions of those Generators that have been scheduled Day-Ahead to provide Spinning Reserve.

(vii) Suppliers selected for Spinning Reserve in the Day-Ahead Market may not re-submit that capacity at a higher price into the Real-Time Market for Spinning Reserve. They may lower the Bid Price of the capacity not selected Day-Ahead to ensure selection in the Real-Time Market.

6.4.2 Specification of Bids: Suppliers of Spinning Reserve must provide the following Bid information:

(i) Response Rate (MW/Minute) of the Generator supplying Spinning Reserve.

(ii) Hours of availability to provide Spinning Reserve.

(iii) Any additional physical data required by the Independent Transmission Provider.

6.5 Calculation of Market Clearing Price

6.5.1 Methodology for Calculation of Prices: The Independent Transmission Provider shall calculate a Market Clearing Price for the Real-Time Market for Spinning Reserve, using the following methodology.

The Independent Transmission Provider shall establish a Supplier Spinning Reserve Price for each Supplier based on its Real-Time Unit-Specific Opportunity Cost (as defined below). The Real-Time Spinning Reserve Market Clearing Price shall be the higher of (i) the highest Supplier Spinning Reserve Price for each Dispatch Interval needed to meet the Independent Transmission Provider's Spinning Reserve Requirement, or (ii) the highest Market Clearing Price in the Dispatch Interval for Supplemental Reserves.

The Unit-Specific Opportunity Costs of a Resource Bidding to sell Spinning Reserve shall be equal to the product of:

(i) the deviation of the set point (MWh) of the Generator that is required to provide Spinning Reserve from the Resource's output level if it had been scheduled or dispatched in economic merit order to provide Energy, times

(ii) the greater of (a) the $/MWh difference between the Real-Time Energy LMP at the generation bus for the Resource and the Bid price for Energy from the Resource (at the megawatt level of the Spinning Reserve set point for the Resource) in the Real-Time Energy Market or (b) zero.

6.5.2 Calculation of Zonal or Locational Prices: Separate Real-Time Spinning Reserve Market Clearing Prices will be calculated for Spinning Reserve located in each distinct Reserve Location for which there is a separate Spinning Reserve requirement. When there are no binding transmission constraints between Reserve Locations, the Real-Time Spinning Reserve Market Clearing Price shall be the same in each of the locations.

6.5.3 Transmission for Operating Reserves. A Supplier located outside of a particular Reserve Location may provide Spinning Reserves if the necessary transmission arrangements to deliver Energy from the Supplier's capacity to the Reserve Location are made. The cost of any transmission service would have to be included in evaluating the total cost of Operating Reserves.

Suppliers scheduled for Spinning Reserve shall not receive Opportunity Cost payments for capacity that was not available to be scheduled to generate Energy.

6.6 Calculation of Additional Payments and Charges

6.6.1 Bid Revenue Sufficiency Guarantee: Resources scheduled for Spinning Reserve in the Real-Time Market are eligible for the Bid Revenue Sufficiency Guarantee, pursuant to Section G.2.3.

6.6.2 Failure to Perform in Real-Time: When reserve is activated, the Independent Transmission Provider shall measure actual performance against expected performance and may charge financial penalties to Suppliers of Spinning Reserve which fail to perform in accordance with their accepted Bids. [The Independent Transmission Provider may file penalties.]

6.6.3 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Real-Time Markets for Spinning Reserves.]

6.7 Market Rules for Shortages or Emergencies

(i) [The Independent Transmission Provider may include in this section market rules, including specification of quantities, calculation of market clearing prices, and determination of out of market payments in the event of a shortfall in the required system requirements for Spinning Reserves due to a shortage of available capacity or an Emergency.]

(ii) In the event of a shortfall of total capacity available for Operating Reserves in the Real-Time Market, the Independent Transmission Provider shall first reduce the amount of Supplemental Reserve that is procured, followed by the amount of Supplemental Reserve, followed by the amount of Spinning Reserve.

6.8 Settlement: The Independent Transmission Provider will provide timely settlement of purchases of Spinning Reserves and sales of Spinning Reserve in the Real-Time Market for Spinning Reserve pursuant to Sections 6.8.1 and 6.8.2.

6.8.1 Payments by Purchasers

(i) The Independent Transmission Provider shall calculate the total obligation for Spinning Reserve for each Load-Serving Entity for each hour of the Operating Day. The hourly total obligation of each Load-Serving Entity in an Operating Day shall equal the product of (a) the total Spinning Reserve Requirement for the Independent Transmission Provider's Service Area for the hour of the Operating Day and (b) the ratio of (1) the Load-Serving Entity's total actual Load in the hour to (2) the total actual Load in the Independent Transmission Provider's Service Area in the hour of the Operating Day. The net obligation for Spinning Reserve of a Load-Serving Entity in an hour of the Operating Day shall be equal to the greater of the Load-Serving Entity's total obligation minus the amount of Spinning Reserve that is Self-Supplied in the Day-Ahead Market or (b) zero.

(ii) For each hour of the Operating Day, each Load-Serving Entity shall be charged an amount equal to the product of (1) the aggregate net amount paid by the Independent Transmission Provider in the Day-Ahead and Real-Time Markets to procure Spinning Reserve for the hour and (2) the ratio of the Load-Serving Entity's net obligation for Spinning Reserve in the hour to the sum of the net obligations for Spinning Reserve of all Load-Serving Entities in the Independent Transmission Provider's Service Area in the hour.

6.8.2 Payments to Suppliers

(i) The Independent Transmission Provider shall pay each Supplier selected to provide more Spinning Reserve in an hour than it was scheduled Day-Ahead the Real-Time Spinning Reserve Market Clearing Price at its location, multiplied by the amount (MW) of Spinning Reserve that Supplier provided that was in excess of the amount scheduled to be provided Day-Ahead, if any.

6.8.3 Payments by Suppliers

(i) The Supplier shall pay the Independent Transmission Provider for any Spinning Reserve that it was scheduled Day-Ahead to provide in an hour but did not provide. The payment will be the Real-Time Spinning Reserve Market Clearing Price at its location, multiplied by the amount (MW) of scheduled Spinning Reserve that Supplier did not provide.

(ii) The Supplier shall pay the Independent Transmission Provider any Additional Payments associated with failure to perform according to its Real-Time schedule, pursuant to Section 6.6.

6.9 Failure to Provide Operating Reserves: If a Supplier reduces its available capacity subsequent to being scheduled to provide Regulation Service or Operating Reserves (either Day-Ahead or in a commitment of Replacement Reserves), and if the Independent Transmission Provider must, as a result, reduce the amount of Operating Reserves that Supplier is scheduled to provide in accordance with this Tariff, the Independent Transmission Provider will first reduce the lowest quality Supplemental Reserve that Generator is scheduled to provide.

If it is still necessary to reduce the amount of Operating Reserves that Supplier is scheduled to provide, the Independent Transmission Provider will reduce the amount, in order of quality, of the higher quality Supplemental Reserves that Generator is scheduled to provide.

Finally, if it is still necessary to reduce the amount of Operating Reserves that Supplier is scheduled to provide, the Independent Transmission Provider will reduce the amount of Spinning Reserve that Generator is scheduled to provide.

If a Supplier scheduled Day-Ahead to provide Operating Reserves trips off-line and consequently is unable to provide Spinning Reserve, or if the amount of Operating Reserves a Supplier is scheduled to provide is decreased due to a reduction in that Supplier's capacity, it shall be charged the Real-Time Operating Reserve price at its location in each hour for the relevant category of Operating Reserves applied to the reduction in the amount of Operating Reserves it was scheduled Day-Ahead to provide at that location.

If the Independent Transmission Provider calls for a Supplier of any category of Operating Reserves (other than a Supplier that has previously tripped off-line) to generate Energy with part or all of the capacity that the Independent Transmission Provider has scheduled to provide any category of Operating Reserves, and that Supplier fails to provide the amount of Energy requested by the Independent Transmission Provider within the time applicable for the scheduled Operating Reserves, the Independent Transmission Provider shall:

(i) not pay the non-performing Supplier for any shortfall in the amount of Energy provided;

(ii) charge the Supplier for any shortfall in the amount of Energy provided, at the Real-Time LMP for Energy at that Supplier's location;

(iii) charge the Supplier a regulation penalty; and

(iv) reduce any Availability payments for the scheduled Operating Reserves, and any Opportunity Cost payments, if applicable, that the Supplier would otherwise have received for the 24-hour billing period in which that Supplier failed to perform as scheduled. The Availability payments and the Opportunity Cost payments, if applicable, that the Supplier would have received will be calculated by multiplying the average ratio of the amount of Energy supplied to the amount of Energy scheduled, during any activation of that Supplier during that 24-hour billing period by the applicable Availability payments and Opportunity Cost payments, if applicable, that the Supplier would otherwise have received.

If a Generator providing Operating Reserves has repeatedly failed to provide Energy when called upon by the Independent Transmission Provider, the Independent Transmission Provider may preclude that Generator from providing Operating Reserves in the future. If a specific Generator has been precluded from supplying Operating Reserves, the Independent Transmission Provider shall require that Generator to pass a re-qualification test before accepting any additional Bids to supply Operating Reserves from that Generator.

7. Real-Time Markets for Operating Reserves—Supplemental Reserves

7.1 General: The Transmission Provider may require additional Supplemental Reserves capability in response to system conditions in the Operating Day. The Real-Time Markets for Supplemental Reserves establish clearing prices and settlement rules for eligible Suppliers of Supplemental Reserve that have offered Supplemental Reserve capacity to the market. The Transmission Provider shall procure Supplemental Reserves for Purchasers that have chosen not to Self-supply or purchase through Bilateral Contracts. Both Generation and Load may Bid to provide Supplemental Reserves in the Real-Time Market if they meet criteria for eligibility.

7.2 Independent Transmission Provider Obligations: The Independent Transmission Provider has the obligation to provide services (i) to (vii) for the Real-Time Markets for Supplemental Reserves. The rules governing these services are contained in this section:

(i) Establish and post on its OASIS Supplemental Reserves criteria and requirements in accord with local reliability authority rules and NERC guidelines.

(ii) Establish and post on its OASIS rules for eligibility to supply Supplemental Reserves in the Real-Time Market.

(iii) Establish and post on its OASIS minimum technical requirements and performance standards for a Generator to provide Supplemental Reserves.

(iv) Establish and post on its OASIS the Bid data requirements and rules and provide the market functions required for determination of hourly Real-Time Supplemental Reserves Market Clearing Prices and selection of Real-Time Supplemental Reserves Market Suppliers. Establish how the pricing rules and selection procedures will be modified in the event of a shortage of Supplemental Reserves capacity during the Operating Day.

(v) Establish and post on its OASIS the rules for determination of any Additional Payments necessary to support efficient operations of the Real-Time Supplemental Reserves and/or the efficient operation of other Real-Time Markets.

(vi) Provide the Settlement functions associated with purchase and sale of Supplemental Reserves in the Real-Time Market.

(vii) Post the Real-Time Supplemental Reserves Market Clearing Prices.

7.3 Purchaser Rules and Obligations

(i) Market Participants with Supplemental Reserves requirements may fulfill their requirement by (1) self-supplying an eligible Generator or Demand-Side Resource, (2) a bilateral contract with an eligible Supplier, or (3) purchasing from the Supplemental Reserves Market.

(2) Self-suppliers and purchasers of Supplemental Reserves through Bilateral Contracts must provide data on location and physical capabilities of the Generator or Supplier providing Supplemental Reserve (see Section 4.2).

7.4 Supplier Rules and Obligations:

(i) During the day, Suppliers that have not been scheduled to provide Supplemental Reserves and which still have capacity that has not been committed for use in any other way may submit Bids to provide Supplemental Reserves to the Independent Transmission Provider.

(ii) The Real-Time Bids may differ from Bids that were made by those Suppliers in the Day-Ahead commitment subject to possible Bid restrictions imposed to mitigate market power.

(iii) Suppliers Bidding to supply Supplemental Reserves that have not already been scheduled to provide Supplemental Reserves may change their Real-Time Bids from one hour to the next subject to possible Bid restrictions imposed to mitigate market power.

(iv) The Independent Transmission Provider shall notify each Supplier of Supplemental Reserves that has been scheduled in the Real-Time dispatch of the amount of Supplemental Reserves it must provide. Any Supplier whose Bid to provide Supplemental Reserves is accepted by the Independent Transmission Provider in the Real-Time dispatch must make its Generators or demand side Resources available for dispatch by the Independent Transmission Provider. Suppliers of Supplemental Reserves shall respond to direction by the Independent Transmission Provider to activate.

7.4.1 Eligibility to Supply

(i) Subject to Independent Transmission Provider requirements, Suppliers of Supplemental Reserves may use Generators and/or Load that are electrically within or outside the Independent Transmission Provider's Service Area.

(ii) Suppliers of Supplemental Reserve may only use Generators and/or Load that meet Independent Transmission Provider standards for Generator performance.

(iii) Suppliers of Supplemental Reserves shall not use, contract to provide, or otherwise commit the capability that is designated to provide Supplemental Reserves to provide Energy, Regulation or Spinning Reserve to any party other than the Independent Transmission Provider.

(iv) Suppliers of Supplemental Reserves shall provide the Bid information specified in Section 4.2.

(v) Suppliers may not use, contract to provide or otherwise commit any capacity on any Resource that has been scheduled to provide Supplemental Reserves in the Day-Ahead commitment or in the Real-Time dispatch.

7.4.2 Specification of Bids: Suppliers of Supplemental Reserves must provide the following Bid information:

(i) Response Rate (MW/Minute) of the Generator supplying Supplemental Reserve.

(ii) Hours of availability to provide Supplemental Reserve.

(iii) Any additional physical data required by the Independent Transmission Provider.

7.5 Calculation of Market Clearing Price for Supplemental Reserve

7.5.1 Methodology for Calculation of Prices: The Independent Transmission Provider shall calculate a Market Clearing Price for each Real-Time Market for Supplemental Reserves, using the following methodology.

The Independent Transmission Provider shall establish a Supplier Supplemental Reserve Price for each Supplier based on Unit-Specific Opportunity Cost (as defined below). The Real-Time Supplemental Reserve Market Clearing Price shall be the higher of (i) the highest Supplier Supplemental Reserve Price needed to meet the Independent Transmission Provider's Supplemental Reserve Requirement for each Dispatch Interval, or (ii) the Market Clearing Price in any Dispatch Interval for any lower quality Supplemental Reserve.

The Unit-Specific Opportunity Costs of a Resource Bidding to sell Supplemental Reserve in each Dispatch Interval shall be equal to the product of:

(i) the deviation of the set point (MWh) of the Generator that is required in order to provide Supplemental Reserve from the Resource's output level if it had been scheduled or dispatched in economic merit order to provide Energy, times

(ii) the absolute value of the difference between the Real-Time Energy LMP at the generation bus for the Resource and the Bid price for Energy from the Resource (at the megawatt level of the Supplemental Reserve set point for the Resource) in the Real-Time Energy Market.

7.5.2 Calculation of Zonal or Locational Prices. Separate Real-Time Supplemental Reserve Market Clearing Prices will be calculated for Supplemental Reserve located in each distinct Reserve Location for which there is a separate Supplemental Reserve requirement. When there are no binding transmission constraints between Reserve Locations, the Real-Time Ancillary Price for Supplemental Reserve shall be the same in each of the locations.

7.5.3 Transmission for Operating Reserves. A Supplier located outside of a particular Reserve Location may provide Supplemental Reserve if the necessary transmission arrangements to deliver Energy from the Supplier's capacity to the Reserve Location are made. The cost of any transmission service would have to be included in evaluating the total cost of Operating Reserves.

7.6 Calculation of Additional Payments and Charges

7.6.1 Bid Revenue Sufficiency Guarantee: Resources scheduled for Supplemental Reserves in the Real-Time Market are eligible for the Bid Revenue Sufficiency Guarantee, pursuant to Section G.2.3.

7.6.2 Failure to Perform in Real-Time: When reserve is activated, the Independent Transmission Provider shall measure actual performance against expected performance and shall charge financial penalties as detailed in Section 6.9, to Suppliers of Reserves which fail to perform in accordance with their accepted Bids. [The Independent Transmission Provider may file penalties.]

7.6.3 Exceptions: Notwithstanding anything to the contrary in this Rate Schedule, no payments shall be made to any Supplier providing Operating Reserves for reserves provided by that Supplier in excess of the amount of Operating Reserves scheduled by the Independent Transmission Provider either Day-Ahead or in any subsequent schedule.

The market clearing price paid to Suppliers of any category of Operating Reserve shall not be determined by any Bid to supply Operating Reserve that has not been accepted by the Independent Transmission Provider.

7.6.5 Other Payments and Charges: [The Independent Transmission Provider may include in this section market rules for any other payments or charges associated with the efficient and reliable operations of the Real-Time Markets for Supplemental Reserves.]

7.7 Market Rules for Shortages or Emergencies:

(i) [The Independent Transmission Provider may include in this section market rules, including specification of quantities, calculation of market clearing prices, and determination of out of market payments in the event of a shortfall in the required system requirements for Supplemental Reserves due to a shortage of available capacity or an Emergency.]

(ii) In the event of a shortfall of total capacity available for Supplemental Reserves in the Real-Time Market, the Independent Transmission Provider shall first reduce the amount of any lower quality Supplemental Reserve that is procured, in order of quality, followed by the amount of higher quality Supplemental Reserves.

7.8 Settlement: The Independent Transmission Provider will provide timely settlement of purchases of Supplemental Reserves and sales of Supplemental Reserves in the Real-Time Market pursuant to Sections 7.8.1 and 7.8.2.

7.8.1 Payments by Purchasers

(i) The Independent Transmission Provider shall calculate the total obligation for Supplemental Reserve for each Load-Serving Entity for each hour of the Operating Day. The hourly total obligation of each Load-Serving Entity in an Operating Day shall equal the product of (a) the total Supplemental Reserve Requirement for the Independent Transmission Provider's Service Area for the hour of the Operating Day and (b) the ratio of (1) the Load-Serving Entity's total actual Load in the hour to (2) the total actual Load in the Independent Transmission Provider's Service Area in the hour of the Operating Day. The net obligation for Supplemental Reserve of a Load-Serving Entity in an hour of the Operating Day shall be equal to the greater of the Load-Serving Entity's total obligation minus the amount of Supplemental Reserve that is Self-Supplied in the Real-Time Market or (b) zero.

(ii) For each hour of the Operating Day, each Load-Serving Entity shall be charged an amount equal to the product of (1) the aggregate net amount paid by the Independent Transmission Provider in the Real-Time Markets to procure Supplemental Reserve for the hour and (2) the ratio of the Load-Serving Entity's net obligation for Spinning Reserve in the hour to the sum of the net obligations for Supplemental Reserve of all Load-Serving Entities in the Independent Transmission Provider's Service Area in the hour.

7.8.2 Payments to Suppliers

(i) The Independent Transmission Provider shall pay each Supplier selected to provide more Supplemental Reserve in an hour than it was scheduled Day-Ahead the Real-Time Supplemental Reserve Market Clearing Price at its location, multiplied by the amount (MW) of Supplemental Reserve that Supplier provided that was in excess of the amount scheduled to be provided Day-Ahead, if any.

7.8.3 Payments by Suppliers

(i) The Supplier shall pay the Independent Transmission Provider for any Supplemental Reserves that it was scheduled Day-Ahead to provide in an hour but did not provide. The payment will be the Real-Time Supplemental Reserve Market Clearing Price at its location, multiplied by the amount (MW) of Day-Ahead scheduled Supplemental Reserve that the Supplier did not provide.

(ii) The Supplier shall pay the Independent Transmission Provider any Additional Payments associated with failure to perform according to its Real-Time schedule, pursuant to Section 7.6.3.

8. Other Real-Time Payments and Charges

8.1 Bid Revenue Sufficiency Guarantee Payments for Replacement Reserves

8.1.1 Payments to Suppliers. The Independent Transmission Provider shall determine, on a daily basis, if any Resource that it has committed to provide Replacement Reserves for the operating day pursuant to Section F.1.8 has not recovered its Start-up, No-load, and Energy Bid Prices through revenues in the Real-Time Energy and Ancillary Services Markets. If the Start-up, No-load, and Energy Bids over the twenty-four (24) hour Operating Day of any such Resource exceed its combined Revenue from the Real-Time Markets for Energy and Ancillary Services, then that Resource's revenue shall be augmented by an additional payment, called the Real-Time Bid Revenue Sufficiency Guarantee payment, in the amount of the revenue shortfall.

8.1.2 Charges to Customers. A purchase of Real-Time Energy is deemed to be made by any Customer whose actual Energy injections in any hour of the Operating Day is less than its injections scheduled for that hour in the Day-Ahead Market, and by any Customer whose actual Energy withdrawals in any hour in the Operating Day exceed its withdrawals scheduled for that hour in the Day-Ahead Market. All uninstructed purchases of Real-Time Energy, *i.e.,* Real-Time Energy purchased by a Customer without being instructed to do so by the Independent Transmission Provider, shall be subject to a Replacement Reserves charge. The Independent Transmission Provider shall calculate Replacement Reserves charges for the Operating Day as follows. The Independent Transmission Provider shall calculate the sum of all uninstructed purchases of Real-Time Energy over the Operating Day and shall compare that sum to the aggregate MWhs of Replacement Reserves that it committed over the Operating Day pursuant to Section F.1.8.

(i) If the sum of all uninstructed purchases of Real-Time Energy greater than or equal to the aggregate MWhs of Replacement Reserves committed over the Operating Day, then the Replacement Reserve charge for each Customer i shall be calculated as:

Replacement Reserve charge for Customer i = $(P/U) \times u_i$;

where:

P is the sum of the aggregate payments made pursuant to Section G.8.1.1 for the Operating Day;

U is the sum of all uninstructed purchases of Real-Time Energy by all Customers (in MWhs) over the Operating Day; and

u_i is the aggregate uninstructed purchases of Real-Time Energy by Customer i over the Operating Day.

(ii) If the sum of all uninstructed purchases of Real-Time Energy is less than the aggregate MWhs of Replacement Reserves committed over the Operating Day, then the Replacement Reserve charge for each Customer i shall be calculated as:

Replacement Reserve charge for Customer i = $(P/R) \times d$;

where:

P is the sum of the aggregate payments made pursuant to Section G.8.1.1 for the Operating Day;

R is the aggregate MWhs of Replacement Reserves that the Independent Transmission Provider has committed over the Operating Day pursuant to Section F.1.8.

u_i is the aggregate uninstructed purchases of Real-Time Energy by Customer i over the Operating Day.

8.1.3 Unrecovered Bid Revenue Sufficiency Guarantee Payments. Any amounts of Bid Revenue Sufficiency Guarantee payments for an Operating Day made pursuant to Section G.8.1.1 that are not recovered through Replacement Reserve charges for the Operating Day pursuant to Section G.8.1.2 shall be recovered in a separate charge to all Load-Serving Entities in the Independent Transmission Provider's Service Area. The charge for each Load-Serving Entity for the Operating Day shall equal to the product of (a) the total amounts of Bid Revenue Sufficiency Guarantee payments for an Operating Day made pursuant to Section G..8.1.1 that are not recovered through Replacement Reserve charges for the Operating Day pursuant to G.8.1.2 and (b) the ratio of (1) the Load-Serving Entity's total actual Load over the Operating Day to (2) the total actual Load within the Independent Transmission Provider's Service Area over the Operating Day.

8.2 Other Real-Time Bid Revenue Sufficiency Guarantee Payments

8.2.1 Payments to Suppliers. The Independent Transmission Provider shall pay each Resource scheduled, committed, or dispatched by the Independent Transmission Provider after the close of the Day-Ahead Market (other than a Resource committed to supply Replacement Reserves) the real-time Bid Revenue Sufficiency Guarantee payment for the Operating Day, calculated pursuant to Section G.2.3(ii).

8.2.2 Charges to Customers. A purchase of Real-Time Energy is deemed to be made by any Customer whose actual Energy injections in any hour of the Operating Day is less than its injections scheduled for that hour in the Day-Ahead Market, and by any Customer whose actual Energy withdrawals in any hour in the Operating Day exceed its withdrawals scheduled for that hour in the Day-Ahead Market. Each Customer purchasing Real-Time Energy shall pay a Real-Time Bid Revenue Sufficiency Guarantee payment. The Bid Revenue Sufficiency Guarantee payment for any Customer i for the Operating Day shall be calculated based on the following formula:

Bid Revenue Sufficiency Guarantee for Customer i = $G \times (C^i / D)$

where:

G is the sum of all Bid Revenue Sufficiency Guarantee payments made for the Operating Day pursuant to Section G.8.2.1;

C_i is the total purchases of Real-Time Energy by Customer i during the Operating Day; and

D is the sum of the total purchases of Real-Time Energy by all Customers over the Operating Day.

Part IV. Market Monitoring

Each Independent Transmission Provider must file a market monitoring plan in accordance with the Commission's regulations as part of this Tariff.

H. Market Power Mitigation and Market Monitoring

1. Market Power Mitigation

1.1 Participating Generator Agreements: The participating generator agreement between the Independent Transmission Provider and a generator will include a provision to require that all available capacity of the generator must be scheduled or offered to the Day-Ahead and Real-Time markets at bids that do not exceed specified Bid caps under non-competitive conditions to be specified in the agreement.

1.2 Determination of Bid Caps

1.2.1 The Safety-Net Bid Cap: The MMU will establish a safety-net Bid cap that will apply to all markets at all times.

1.2.2 Generator-specific Bid Caps: The MMU will establish for each Generator identified in Section H.1.4.1 below Bid caps that may apply to each Bid-in parameter when mitigation is warranted. These shall include: Bid caps for Energy, regulation service, operating reserves, start-up costs, no-Load costs, incremental and decremental Energy costs, and any other parameter allowed to vary in Day-Ahead and Real-Time markets.

1.3 Determination of Available Capacity: Available capacity is all capacity not scheduled or on an outage.

1.3.1 Adjustments to Available Capacity to Reflect Risk of Forced Outages in Real-Time Market: Independent Transmission Provider may file provisions.

1.3.2 Available Capacity Reduced by Forced Outages Subject to Audit: Units declaring a forced outage would be subject to audit by the MMU. If the outage was not proved to be justified, then the Generator shall be subject to a penalty. [The Independent Transmission Provider shall specify the type of penalty.]

1.4 Determination of Non-competitive Conditions

1.4.1 Local Non-competitive Conditions: The MMU shall identify specific Generators that are frequently needed to support the operation of the grid and sellers that own facilities in identified Load pockets with fewer than ____ independent suppliers. Participating Generator Agreements for these entities will require that they be subject to Local Market Power Mitigation.

1.4.2 Other Non-competitive Conditions: The MMU shall identify other non-competitive conditions as necessary.

1.5 Triggering Mitigation

1.5.1 Market Power Mitigation Independent of Market Conditions: The Independent Transmission Provider may not accept any Bid into the Day-Ahead or Real-Time markets that exceeds the higher of: (a) the safety-net Bid cap specified in Section H.1.2.1; or (b) the bid cap specified in a Participating Generator Agreement.

1.5.2 Market Power Mitigation Triggered by Section H.1.4.1: When mitigation is triggered by Section H.1.4.1, the units will be required to offer all available capacity to the Day-Ahead and Real-Time markets at bids that do not exceed applicable bid caps determined in H.1.2.2.

1.5.3 Market Power Mitigation Triggered by Section H.1.4.2: To be specified.

2. Market Monitoring Plan

The transmission and power markets administered by the Independent Transmission Provider will be monitored on an on-going basis by the Market Monitoring Unit (MMU). The MMU reports directly to the Commission and the governing board of the transmission provider.

2.1 Data Requirements and Data Collection: The MMU shall collect and evaluate data provided by the Independent Transmission Provider and Market Participants in order to identify inefficiencies in the markets or the market design, and individual Market Participant behavior that may be a prohibited exercise of market power or a violation of this Tariff or other market rules.

2.1.1 Obligations of Market Participants: As a condition of participating in the markets operated by the Independent Transmission Provider, all Market Participants shall be required to comply with information requests from the MMU. Any disputes concerning whether the information is necessary or how the information is to be provided or how any confidential information could be used should first be attempted to be resolved either through dispute resolution or the Commission's Office of Market Oversight and Investigations (Hotline). If the parties are then unable to resolve the dispute, a complaint under Section 206 of the Federal Power Act may be filed.

2.1.2 Generator-Specific data: The MMU shall have the responsibility to collect all Generator-specific data needed to evaluate whether a seller is exercising market power and to establish Bid restrictions that may be imposed when markets are not sufficiently competitive. The data shall include, at a minimum: start-up, no Load, and shut-down costs, environmental restrictions, fuel costs, maintenance costs, heat rates, ramp rates, high and low operating levels, and minimum run times.

2.1.3 Data Acquired in the Course of Conducting Market Operations: The MMU shall have immediate access to all Bid data submitted to the Independent Transmission Provider.

2.1.4 Other Publically Available Data: The Market Monitor shall collect all data needed to assess the overall competitiveness of its markets. The data would include, but not be limited to, information on market shares of Generation Capacity by type and location, information on planned and unplanned Generator and transmission outages, and plans for transmission expansions and upgrades, and Generator interconnection requests.

2.1.5 Confidentiality: All information obtained by the MMU, that is specific to a Market Participant, shall be treated confidentially.

2.2 Framework for Analyzing Market Structure and Generator Conduct

2.2.1 Obligations of the Market Monitor: The MMU shall conduct a structural analysis of the markets in the region to include in a state of the market report to the Commission, the committee of state representatives, and the transmission provider's Board of Directors. In addition, the MMU must evaluate the conduct of Market Participants. Any flaws in the market rules that are identified by the Market Monitor, and any Market Participant conduct that indicates exercises of market power, shall be remedied prospectively, unless the conduct violates existing rules, in which case the consequences shall be predetermined and specified in this Tariff.

2.2.1 Structural Analysis: The MMU shall develop an analysis of the overall competitiveness of the markets operated by the Transmission Provider. The analysis will be performed at least annually and will report on the following at a minimum: market concentration by Generator type and region, transmission constraints and Load pockets that may give rise to market power concerns, conditions for entry or new supply, the development of demand response, and development of a competitive benchmark.

2.2.2 Conduct Analysis: The MMU will monitor the conduct of individual Market Participants. The Market Monitor shall review planned transmission and generation outages to ensure that scheduling outages are not used to enhance or create opportunities to exercise Generator market power. Analysis of Market Participant conduct may include a review of Bidding behavior to identify any auction design flaws that may give Market Participants an unanticipated incentive and ability to manipulate market-clearing prices or up-lift payments. Finally, the Market Monitor shall evaluate the effectiveness of the Participating Generator Agreements in mitigating market power where market structure is not sufficiently competitive.

2.3 Annual Reports: No later than May 31 of each year, the Market Monitor shall file a State of the Markets Report with the Commission which includes the results of the Market Monitor's structural and conduct analyses. This report shall address such items as market concentration, demand response programs, Load pockets, and transmission constraints and an assessment of the performance of the markets administered by the Transmission Provider. In addition, this report shall identify any actions taken by the Market Monitor.

2.4 Periodic Reports: The Market Monitor shall submit a report to the Commission if it detects behavior that cannot be cured within the Market Monitor's authority or if it detects behavior that would require a change in market rules. These reports should be made as soon as practicable after the behavior is detected.

3. Rules for Market Participant Conduct: Market Participants must comply with the following rules:

3.1 Physical Withholding: Entities may not physically withhold the output of an Electric Facility (Generating unit or Transmission Facility) by (a) falsely declaring that an Electric Facility has been forced out of service or otherwise become unavailable, or (b) failing to comply Section H.1.5.2.

3.2 Economic Withholding: Entities may not economically withhold by submitting high bids that are not consistent with the caps specified in Section H.1.2.

3.3 Availability Reporting: Entities must comply with all reporting requirements governing the availability and maintenance of a Generating Unit or Transmission Facility, including proper Outage scheduling requirements. Entities must immediately notify the Transmission Provider when capacity changes or resource limitations occur that affect the availability of the unit or facility or the ability to comply with dispatch instructions.

3.4 Factual Accuracy: All applications, schedules, reports, or other communications to the Transmission Provider or the Market Monitor must be submitted by a responsible company official who is knowledgeable of the facts submitted. All information submitted must be true to the best knowledge of the person submitting the information.

3.5 Information Obligation: Entities must comply with requests for information or data by the Market Monitor or the Transmission Provider that are consistent with the Tariff.

3.6 Cooperation: Entities must assist and cooperate in investigations or audits conducted by the Market Monitor.

3.7 Physical Feasibility: All Bids or schedules that designate Resources must be physically feasible within the limits of the Resource, *i.e.,* the Resource is physically capable of supplying the Energy, Ancillary Service, or demand response needed to fulfill a schedule or Bid according to the physical limitations of the Resource.

3.8 Enforcement: The Market Monitor is responsible for the enforcement of the rules in this section. Violations of these rules will be subject to the following penalties: [to be added]

I. Long-Term Resource Adequacy

This section sets forth terms and conditions requiring each Load-Serving Entity to meet its share of the region's Resource Adequacy Requirement. The Resource Adequacy Requirement will ensure that in the future each Load-Serving Entity will have secured generation, transmission, and demand response resources sufficient to meet real-time load and a reasonable operating reserve margin necessary to maintain the stable and reliable operation of the transmission system.

[Additional details will be completed and filed by each Independent Transmission Provider as part of its compliance filing.]

1. Data Submission for the annual forecast of future regional load

(i) [There may be regional variation in forecast methodology. Some regions may wish to do a bottom up forecast. The following wording will then be needed.] [Annually, on or before __________ (each Independent Transmission Provider shall insert the relevant date here), each Load Serving Entity shall submit its demand forecast for the Planning Horizon.]

2. Assignment of Resource Adequacy Requirements

(ii) Annually, on or before __________ [each Independent Transmission Provider shall insert the relevant date here], the Independent Transmission Provider shall assign a share of the region's Resource Adequacy Requirement to each Load Serving Entity within the region based on the ratio of the load.

3. Load Serving Entity's submission for Resource Adequacy Requirements

(i) Annually, on or before __________ [each Independent Transmission Provider shall insert the relevant date here], each Load Serving Entity shall submit a proposed plan to meet its assigned Resource Adequacy Requirement to the Independent Transmission Provider.

(ii) Plans for meeting the assigned Resource Adequacy Requirement may rely upon generation, transmission, and/or demand response, subject to the standards set forth in this section of the Tariff, and Independent Transmission Provider's review of operational feasibility.

(iii) The Independent Transmission Provider shall audit each plan for compliance with the standards set forth in Section I.4 and for operational feasibility. [Each Independent Transmission Provider shall establish a review and resubmission process, with reasonable time frames, to achieve compliant and operationally feasible plans within a specified end date.]

4. Resource Adequacy Requirement Standards

(ii) Each Load-Serving Entity must satisfy the Independent Transmission Provider that the resources to be relied upon for future Resource Adequacy Requirements are in compliance with the standards of this section of the Tariff and are operationally feasible, dedicated to serving the Load-Serving Entity without prior or conflicting claim, and can be delivered to the load to be served as and if needed to meet future requirements.

(ii) [Each Independent Transmission Provider shall list in its open access electricity transmission Tariff specific requirements it intends to impose on each Load-Serving Entity such that the Load Serving Entity's resources qualify to meet its share of the Resource Adequacy Requirement.]

5. Penalties

[Each Independent Transmission Provider shall list in its open access electricity transmission Tariff specific penalties it intends to impose.]

(i) Each Load-Serving Entity that has not met its allocated share of the Resource Adequacy Requirement, shall be subject to penalty rates for spot market energy purchases during the last year of the Planning Horizon to the extent of the resource shortage whenever the Independent Transmission Provider's market has available less than a minimally acceptable level of operating reserves.

(ii) Penalties will increase on a graduated basis as the Independent Transmission Provider's operating reserves level falls below minimally acceptable levels. (For example, for deficiencies up to 1 percent, the penalty would be $500/MWh, plus the prevailing market price for energy. As the operating reserve level falls, the premium of the penalty over the prevailing market price for energy would increase: over 1 percent up to 2 percent, the penalty would be $600/MWh; over 2 percent up to 3 percent, the penalty would be $700/MWh; and so forth.)

6. Curtailment

(i) A Load-Serving Entity that fails to implement curtailment (load shedding) when ordered by the Independent Transmission Provider shall be assessed a penalty of $1,000 per MWh, in addition to the LMP, for all unauthorized energy taken following an instruction to implement curtailment (load shedding).

Part V. Other

J. Generation Interconnection Procedures (to be provided in a separate rule)

Part VI. Transmission Planning and Expansion

K. Transmission Planning and Expansion

Each Independent Transmission Provider must file its transmission planning and expansion plan as part of this Tariff.

Part VI. Pro Forma Service Agreements

Form Of Service Agreement For Network Access Transmission Service

1.0 This Service Agreement, dated as of___________, is entered into, by and between___________ (the Independent Transmission Provider), and ___________ (''Customer'').

2.0 The Customer has been determined by the Independent Transmission Provider to have a Completed Application for Network Access Service under the Tariff.

3.0 The Customer has provided to the Independent Transmission Provider an Application deposit, if applicable, in accordance with the provisions of Section B.2.2 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Independent Transmission Provider agrees to provide and the Customer agrees to take and pay for Network Access Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 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.

Independent Transmission Provider:

____

____

____

Customer:

____

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Independent Transmission Provider:

By: ____________________________________

Name

Title __________________________________

Date __________________________________

Customer:

By: ____________________________________

Name

Title __________________________________

Date __________________________________

Specifications For Network Access Service for Customers with Designated Resources and for Long-Term Customers without Designated Resources

1.0 Term of Transaction: ______________

Start Date: ________________________

Termination Date: ___________________

2.0 Description of capacity and Energy to be transmitted by Independent Transmission Provider including the electric Service Area in which the transaction originates. ________

____

3.0 Receipt Points or Network Resource(s):

____

Delivering Party: ____________________

4.0 Delivery Points or Network Load: ______

Receiving Party: ____________________

5.0 Designation of party(ies) subject to reciprocal service obligation: ______________

____

____

____

6.0 Name(s) of any Intervening Systems providing transmission service: ___________

____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below plus any applicable Congestion Charges. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Network Access Charge: _____________

____

8.2 System Impact and/or Facilities Study Charge(s): ______________________________

____

____

8.3 Direct Assignment Facilities Charge: __

____

8.4 Ancillary Services Charges: _________

____

____

____

____

____

____

Form of Service Agreement for Market Services

1. This Service Agreement dated as of _______________ is entered into by and between _______________ (Independent Transmission Provider) and _______________ (Customer).

2. The Customer represents and warrants that it has met all applicable requirements set forth in the Independent Transmission Provider's Tariff and has complied with all applicable Procedures under the Tariff.

3. The Independent Transmission Provider agrees to provide and the Customer agrees to pay for Market Services in accordance with the provisions of the Independent Transmission Provider's Tariff and to satisfy all obligations under the terms and conditions of the Independent Transmission's Provider's Tariff, as may be amended from time-to-time, filed with the Federal Energy Regulatory Commission (Commission). The Independent Transmission Provider and the Customer all agree that this Service Agreement shall be subject to, and shall incorporate by reference, all of the terms and conditions of the Independent Transmission Provider's Tariff and Procedures.

4. It is understood that, in accordance with the Independent Transmission Provider's Tariff, the Independent Transmission Provider may amend the terms and conditions of this Service Agreement by notifying the Customer in writing and make the appropriate filing with the Commission.

5. The Customer represents and warrants that:

(a) The Customer is an entity duly organized, validly existing and/or otherwise qualified to do business under the laws of the State of ___________ and is in good standing under its [insert organizational document] and the laws of the State of [insert state of organization];

(b) This Service Agreement, or any Transaction entered into pursuant to the Service Agreement, as applicable, has been duly authorized;

(c) The execution, delivery and performance of this Service Agreement will not materially conflict with, constitute a material breach of, or a material default under, any of the terms, conditions, or provisions of any law or order of any agency of government, the [insert organizational document] of the Customer, any contractual limitation, organizational limitation or outstanding trust indenture, deed of trust, mortgage, loan agreement, other evidence of indebtedness, or any other agreement or instrument to which Customer is a party or by which it or any of its property is bound, or in a material breach of, or a material default under, any of the foregoing; and

(d) This Service Agreement is the legal, valid, and binding obligation of the Customer 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.

The Customer warrants and covenants that, during the term of the Service Agreement, the Customer shall be in compliance with all federal, state, and local laws, rules, and regulations related to the Customer's performance under the agreement.

4. Service under this Service Agreement shall commence on the later of: _____________, or such other date as it is permitted to become effective by the Commission. Service under this Service Agreement shall terminate on ___________.

5. The Independent Transmission Provider agrees to provide and the Customer agrees to take and pay for, or to supply to the Independent Transmission Provider, Energy, capacity, and Ancillary Services in accordance with the provisions of the Independent Transmission Provider's Tariff and this Service Agreement.

6. 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:

Independent Transmission Provider:

____

____

____

Customer:

____

____

____

7. Cancellation Rights:

If the Commission or any regulatory agency having authority over this Service Agreement determines that any part of this Service Agreement must be changed, the Independent Transmission Provider shall offer to the Customer an amended Service Agreement reflecting such changes. In the event that the Customer does not execute such an amendment within thirty (30) days, or longer if the Parties mutually agree to an extension, after the Commission's action, this Service Agreement and the amended Service Agreement shall be void.

8. Early Termination by the Customer:

The Customer may terminate service under this Service Agreement no earlier than ninety (90) days after providing the Independent Transmission Provider with written notice of the Customer's intention to terminate; except that a Load-Serving Entity must continue to take service under the Independent Transmission Provider's Tariff as long as it continues to serve Load within the Independent Transmission Provider's Service Area. In the event that tax-exempt financing of a Customer is jeopardized by its participation under this Service Agreement, the Customer is jeopardized by its participation under this Service Agreement, the Customer may terminate this Service Agreement upon thirty (30) days written notice to the Independent Transmission Provider. The Customer's provision of notice to terminate service under this Service Agreement shall not relieve the Customer of its obligation to pay any rates, charges, or fees due under this Service Agreement, and which are owed as of the date of termination.

9. The Customer hereby appoints the Independent Transmission Provider as its agent for the limited purpose of effectively transacting on the Customer's behalf in accordance with the Customer's written instructions, listed herein and the terms of the Independent Transmission Provider's Tariff and Procedures. The Customer agrees to pay all amounts due and chargeable to the Customer in accordance with the terms of the Independent Transmission Provider's Tariff and Procedures.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Independent Transmission Provider: ______
By: ______
Dated: ______
Title: ______
Customer: ______
By: ______
Dated: ______
Title: ______

Form of Participating Generator Agreement

[To be provided by Independent Transmission Provider.]

Part VII. Attachments

Attachment A—Methodology To Assess Available Transfer Capability

To be filed by the Independent Transmission Provider based on the following guidelines:

Available Transfer Capability must be calculated on a regional basis by an independent entity. In an RTO or ISO, the Independent Transmission Provider may calculate Available Transfer Capability. Vertically integrated utilities not a part of an RTO or ISO must contract with an independent entity to calculate Available Transfer Capability on its system. The calculation of Available Transfer Capability must take into account the effect of other transmission systems in the interconnection (*e.g.*, loop flow and parallel path flows).

Attachment B—Methodology for Completing a System Impact Study

To be filed by the Independent Transmission Provider.

Attachment C—Network Operating Agreement

To be filed by the Independent Transmission Provider.

Attachment D—Index Of Network Access Service Customers

Customer	Date of Service Agreement

Attachment E—Index Of Market Services Customers

Customer	Date of Service Agreement

Attachment F—Rates

To be filed by the Independent Transmission Provider.

Attachment G—List of Existing Transmission Contracts

Customer	Commission Designation	Date of Contract	Termination Date

Appendix C—Examples of Flaws in the Current Regulatory Environment

We set forth below specific examples of undue discrimination and impediments to competition that continue to exist in the electric industry. Some of the examples that we provide do not use specific names because they are for the most part based on complaints made through the Commission's Enforcement Hotline, which are handled on a confidential basis. Other examples, which illustrate the potential for discrimination, establish that transmission providers have both the incentive and ability to exercise transmission market power against competitors in the market to supply energy.

Available Transfer Capability and Affiliates

The following is an example derived from informal, non-public inquiries to the Commission [1] regarding a transmission provider favoring itself or its affiliate using Available Transfer Capability postings:

In February, a competing generator recognizes an opportunity to sell power into a vertically integrated transmission provider's system during the summer months (June, July, and August) and, therefore, requests monthly firm service for the desired points for that time period. The transmission provider, which would prefer that its merchant function capture the sales anticipated by the competitor, now must evaluate whether sufficient Available Transfer Capability will be available to honor its competitor's request. Although the formula for calculating Available Transfer Capability is required to be public, the transmission provider has the sole responsibility for, and a great deal of discretion in, its calculation, and will be very conservative in its estimates of expected contingencies, outages and the like. In this example, the transmission provider assumes two generating units will be unavailable, reducing Available Transfer Capability below the level where the requested transmission can occur, so it denies the request for summer service. But after the competitor's request is denied, the transmission provider's affiliate can ask in May for weekly firm service over the summer. So, when the affiliate's request is made, it is granted. Discretion on the part of the transmission provider in calculating Available Transfer Capability coupled with the affiliate's knowledge of how the calculations work enable the affiliate to secure the necessary firm service and win the sale opportunity.

Discretionary Use of TLRs

The following is another example derived from informal, non-public inquiry by the Commission regarding how TLRs are used.[2]

The facts: There are three neighboring, interconnected transmission systems, WestCo, CentralCo, and EastCo. (Their relative locations match their names).

CentralCo has 10,000 MW of generation and 8,000 MW of load west of a constrained line that divides its system. The line is limited to 1,500 MW of transfer capability. CentralCo has 1,000 MW of generation and 2,000 MW of load east of the constraint. Its cost of generation on either side of the constraint is comparable, and averages about $25 per MWh.

Under its normal dispatch pattern, CentralCo would generate 1,000 MW from its generation in the east to serve the eastern load, and would generate 9,000 MW from its western generation, 8,000 MW to meet its western load and 1,000 to meet the remainder of the 2,000 MW load in the east. This means that 1,000 MW of generation would usually flow across the constrained line for CentralCo to meet its own load, leaving 500 MW of west-to-east ATC on the constrained line.

NewGen, a generator located in WestCo's service area, wants to sell 100 MW for one day to a buyer in EastCo's service area. NewGen's cost of generation is $22 per MWh.

To make the sale, NewGen must secure 100 MW of transmission across CentralCo's system (including the constrained line), to make the sale. Therefore, NewGen requests transmission service through CentralCo's system. Under normal operating conditions, CentralCo's constrained line has available 500 MW of Available Transfer Capability, leaving plenty of transfer capability to accommodate the sale. Since its OASIS lists 500 MW of Available Transfer Capability, CentralCo grants the request.

If CentralCo were an RTO, it would have no financial interest in which generator makes any particular sale, and would focus on ensuring optimal and reliable system operation. Thus, it would dispatch the system to ensure that the 100 MW NewGen transaction would flow, since it could do so while still optimizing the dispatch of the CentralCo generators. But CentralCo has a financial incentive to block the NewGen transaction in order to make the sale itself and it has the information to make it happen. CentralCo, as transmission provider, knows the flow patterns on its system and the identity (and affiliation) of all generators flowing power on its system. This means that CentralCo's transmission arm would not need to engage in any prohibited off-OASIS

[1] Because this example is based on non-public inquiries, we have not identified the companies.

[2] Because this example is based on non-public inquiries, we have not identified the companies.

communications to dispatch the system in a way that favors its own affiliate.

CentralCo can block a portion of the competitor's transaction by changing its own dispatch pattern and declaring a TLR across the constrained line. CentralCo would reduce generation on the east side to 500 MW and increase generation from the west by the same amount to meet the eastern load. This would increase its own use of the constrained line to 1,500 MW which, in addition to the 100 MW of scheduled use by NewCo, would exceed the thermal limits of the line. CentralCo, as security coordinator for its own system, has great discretion as to when and for how long to declare a TLR across the constrained line. In this situation, rather than redispatching its own generators to accommodate NewGen's transaction, it could declare a TLR and curtail a portion of the NewGen's transmission transaction.

By curtailing transmission for a portion of the competitor's sale, this TLR allows CentralCo to step in to provide EastCo's needed 100 MW (following NewCo's transmission curtailment), possibly at an inflated price due to the TLR and the buyer's need to immediately secure replacement power.

The Commission is concerned that the use of emergency procedures offers opportunities for discrimination. A high incidence of TLRs reduces certainty in the market because it frustrates the expectations of bulk power sellers and their customers.[3] In turn, it provides a disincentive for market participants to take transmission risks and decreases overall liquidity in the transmission market.[4] The practice of using TLRs to manage congestion contributes to transmission and energy prices that are not just and reasonable and must be remedied.

Lack of Common Set of Rules Governing Transmission

1. Balancing Authority

A market participant that operates a control area may derive a market benefit. The primary function of a control area operator is to maintain a balance between the energy coming onto the grid and the energy being taken off. The North American Electric Reliability Council (NERC) refers to this primary function as balancing and the responsible entity as the balancing authority.[5] The balancing authority has generating resources that it may call on for balancing but also may rely on a neighboring balancing authority for balancing energy, which it must pay back. The payback is typically accomplished by returning energy at a later time.

A transmission customer outside the organized spot market of an ISO or RTO is expected to keep its own grid energy inputs and withdrawals in balance. For example, the customer may be a municipal utility that buys 50 megawatts from noon to 1 o'clock to meet a load that is expected to hover around 50 megawatts at that hour. The transmission customer cannot achieve exact balance in part because retail loads are not completely predictable.[6] To the extent the customer does not achieve exact balance, the balancing authority supplies or absorbs energy for balancing, charging the customer for the energy. For an excessive deviation from the scheduled amount of energy delivery, the transmission customer may have to pay a penalty rate under the public utility's tariff, intended to encourage good scheduling behavior so as to maintain reliable system operation.

A balancing authority outside an RTO or ISO is today typically also a market participant that serves its own power customers. In most cases, it is a large vertically integrated public utility that generates and buys power to meet the power needs of its native load. Such a balancing authority may be able to lower the cost of acquiring balancing energy and achieve a competitive advantage over other market participants that do business on its transmission system. It can rely on a neighboring balancing authority to loan it energy without having to pay for the energy. Further, it may avoid a penalty for excessive deviation. It can later return the energy taken in kind to the neighboring authority and may thus face a lower balancing cost than other energy providers. Although this problem may incur infrequently, it results in an undue cost preference for the investor-owned utility and its customers vis-a-vis the costs that other energy providers incur and pass on to their customers.

NERC has recognized a related reliability problem associated with excessive unplanned borrowing of energy in a highly competitive market and is in the process of writing new rules to alleviate this problem.[7] Because compliance with NERC's rules is voluntary, one NERC region filed on behalf of the public utilities in its region so that its rule relating to balancing would be mandatory. On May 31, 2000, the Commission approved a tariff filed by the East Central Area Reliability Council, which is the NERC regional reliability council for an area centered around Indiana, Ohio, and western Pennsylvania.[8] The tariff, designed to maintain reliability in an increasingly competitive region, is intended to eliminate any economic incentive that may exist under current reliability rules for a particular balancing authority to borrow large amounts of energy from neighboring authorities when the price of power is high and return it in kind when the price is low.[9] It does not, however, fully eliminate the economic advantage that a balancing authority that is also a market participant may have over other energy suppliers.

The Commission, in the proposed rule leading to Order No. 2000, using the then-current terminology of the control area operator, said that, in an RTO,

> unequal access to balancing options can lead to unequal access in the quality of transmission service, and that this could be a significant problem for RTOs that serve some customers who operate control areas and other customers who do not.[10]

The Commission concluded in Order No. 2000 that

> control area operators should face the same costs and price signals as other transmission customers and, therefore, also should be required to clear system imbalances through a real-time balancing market. We believe that providing options for clearing imbalances that differ among customers would be unduly discriminatory.[11]

The Commission has not addressed this issue generically, however, for public utility transmission providers that are not in an RTO. There is a need for a tariff that addresses this issue explicitly for all public utility transmission providers.

2. Receipt and Delivery Point Flexibility

The Order No. 888 *pro forma* tariff provides nondiscriminatory rules governing the designation of receipt points, where power enters the transmission provider's system, and delivery points, where power exits the system. There are different such rules for network integration and point-to-point transmission customers, as required by the Order No. 888 *pro forma* tariff. Transmission customers say that these tariff provisions allow a vertically integrated public utility with a native load to provide itself with greater flexibility regarding designation of receipt and delivery points through practices that have become known in the industry as ''parking'' and ''hubbing.''

[3] *See* Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets In The United States (Nov. 1, 2000), *available in* <*http://www.ferc.gov/electric/bulkpower/midwest.pdf*>, at 2–32. See Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets In The United States (Nov. 1, 2000), *available in* <*http://www.ferc.gov/electric/bulkpower/southeast.pdf*>, at 3–38.

[4] *See* Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets In The United States (Nov. 1, 2000), *available in* <*http://www.ferc.gov/electric/bulkpower/midwest.pdf*>, at 2–33 (reporting eroded confidence and decreased liquidity in the Midwest market).

[5] Because most transmission systems were operated by vertically integrated utilities that performed many types of control functions, the term ''control area operator'' now lacks precision regarding which of these functions is being referred to in a particular context. Recently, NERC adopted new terminology for use in rewriting its reliability standards. It is eliminating the terms ''control area'' and ''control area operator'' and replacing these with several other terms that describe more precisely the functions performed. NERC refers to the entity responsible for maintaining system frequency by arranging for generation to balance load as the ''balancing authority.'' It is this function that is the subject of the first example. See The NERC Functional Model: Functions and Relationships for Interconnected Systems Operation and Planning (visited June 11, 2002) <*http://www.ferc.gov/Electric/RTO/mrkt-strct-comments/02–19–02/CACTR-Final-Report-Functional-Model.pdf*> for more information on the NERC functional model. *See also* Transcript of Assignment of RTO Characteristics and Functions Technical Conference, Docket No. RM01–12–000, at 12–34 (Feb. 19, 2002).

[6] A customer can achieve such balance through dynamic scheduling, which effectively takes it out of the control area.

[7] *See, e.g.*, Board of Trustees Meeting Highlights (visited May 31, 2002) <*http://www.nerc.com/pub/sys/all_updl/docs/bot/bot0106h.pdf*>

[8] *See* East Central Area Reliability Council, 91 FERC ¶ 61,197 (2000).

[9] *See id.* at 61,693–94.

[10] Order No. 2000 at 31,142.

[11] *Id.*

To illustrate, a point-to-point transmission customer, such as a power marketer, may be required to reserve transmission for a complete transaction, that is, from an actual generator to an actual power-consuming load. If it is announced today, for example, that generation will be available tomorrow from a particular generator, the marketer may be able to buy the power but unable to reserve the transmission if it has not yet identified a buyer and named its location on the grid. That is, it can name a point of receipt but cannot yet name a point of delivery, so it may be denied a reservation for firm transmission service.

A vertically integrated transmission provider with a native load, however, can buy the power from the same generator, naming that generator as the point of receipt and its native load network as the point of delivery, saying it intends to reduce its own generation to meet its native load power needs. The transmitting public utility is given a transmission reservation. Later, the public utility can find a buyer for the power and say it is making a sale from its freed-up generation, designated as the point of receipt, to the buyer's point of delivery—taking a second transmission reservation for the same power. In effect, the public utility will have reserved transmission for a purchase from the generator and a sale to the buyer in a manner that is not available to the marketer. The public utility is said to have ''parked'' the power at its native load location while it sought a buyer for the power. Parking can also occur if the buyer is known and transmission to the buyer is reserved, allowing the public utility time to search for a seller to match the buyer's power needs. The time delay involved in parking affords flexibility to a vertically integrated transmission provider that is not available to all transmission customers.

''Hubbing'' is similar but does not necessarily involve a time delay. Instead, it involves having more than one seller or more than one buyer, or both. Using the method just described for parking, a transmitting public utility with a native load may reserve transmission to buy power from several sellers and to sell power to several buyers. In effect, it may use its combined native load transmission network location as a hub for trading. It may acquire a portfolio of generators from which to obtain power to meet the power needs of a collection of power buyers, without having to match individual buyers and sellers. This hubbing allows the public utility to capture market efficiencies by combining resources to satisfy collective needs, and to gain a competitive advantage over others who cannot establish a hub because they are required by Point-to-Point Transmission Service rules to match a particular generator with a particular load for each transmission reservation.

This example shows another undesirable difference between two transmission services available to both wholesale and unbundled retail customers, Network Integration Transmission Service and Point-to-Point Transmission Service.

Today, the Commission concludes that the inherent differences in flexibility between the two types of tariff services, including the one described above, are resulting in undue preferences and thereby impeding the most efficient trading of power over the interstate transmission grid. Accordingly, the Commission proposes to create a single transmission service and equalize the playing field so that all transmission customers can park, hub or exercise equal creativity and flexibility in structuring transactions and serving customers.

3. Transmission Transfer Capability Set Aside for Reliability

Transmission transfer capability may be set aside by the transmission provider for either of two reliability-related reasons. One relates to the reliability of the transmission system itself and the other relates to generation reliability. As an example of the first, the power loading on a transmission line may be less than the line's capacity so that it can take up the power flows it must absorb if a parallel line should go out of service. The industry refers to this type of unused transmission capacity as a transmission reliability margin, or TRM. While reliability rules forbid a transmission provider from loading a line beyond its reliability limit, these rules are not necessarily mandatory or enforceable. However, there have been few complaints about discriminatory violations of TRM reliability limits.

Most complaints have related to transmission transfer capability that is set aside to provide for adequate generation. A vertically integrated public utility may have decided in the past that, to achieve adequate generation resources (including reserves), it was more economical to build stronger transmission interconnections with neighbors that could share their extra generation when needed than to build extra generation in its own service area. When Order No. 888 was under consideration, such utilities argued that some transmission transfer capability should be set aside for this generation reliability function.[12] They asserted that, if others were allowed to purchase firm rights to this transmission capability, it would not be available to the public utility when needed for the generation reliability purpose for which it was built.[13] The term used for this type of transmission set aside is capacity benefit margin (CBM). Order No. 888 permitted utilities to have CBM if they fully explained and justified the amount set aside.[14] The CBM set-aside practice is not used universally; some utilities do not claim a capacity benefit margin. Moreover, where it is used, there is regional variation in its implementation.

Since Order No. 888 issued, at least two issues related to CBM have been controversial. One is whether all network transmission customers, including for example municipal utilities within the transmission owner's service territory, have an equal opportunity to set aside transmission for this purpose. The second is whether those who set aside transmission for CBM are reserving it and paying for it under the terms of the *pro forma* tariff.

The second issue is best explained with an example. Suppose a transmission-owning public utility sets aside 100 MW of transfer capability at its interface with a neighboring utility to help ensure adequate generation for the public utility's native load customers. Suppose further that the public utility's native load is 600 MW, and the collective amount of point-to-point transmission customer imports is 200 MW and the line's total capacity is 900 MW. Under the usual method of allocating transmission costs to customers, the point-to-point customer would pay for and receive 200 MW of transmission service and the public utility would pay for 600 MW of transmission system cost but receive 600 MW of transmission service and 100 MW of reserved capacity. In some cases, the transmission provider's merchant affiliate has used the CBM set-aside on a non-firm basis to make sales without paying for the transmission capacity used.

In 1998 the Commission received complaints alleging that some transmission-owning utilities were inappropriately reducing Available Transfer Capability to reflect transmission reliability requirements and capacity benefit margins.[15] The Commission observed in *WPPI* that the determination of CBM was made differently in the Available Transfer Capability calculations of various utilities and was not explained in one tariff.[16] The Commission stated that it was ''concerned that the exercise of this discretionary adjustment can turn on considerations (such as the reduction of power supply costs and limiting the generation supply options of competitors) that involve the transmission provider's merchant arm rather than its transmission function.''[17]

In 1999, the Commission initiated a generic inquiry into policies for transmission reliability set-asides. In particular, the Commission convened a conference in May 1999 in which it examined the practices of use, and the alleged abuses, of CBM.[18] Transmitting utilities had been accused of using CBM designations to withhold transmission transfer capability from the wholesale electric transmission market. The Commission also requested comments on the subject. One commenter stated:

> Even NERC acknowledges that there is a wide disparity in the magnitudes of TRM [transmission reliability margin] and CBM applied by transmission providers across an interconnection, especially in the quantification of CBM. The reason for this disparity is the absence of an enforceable industry standard—or more appropriately, a Commission rule—for the definition of CBM.[19]

[12] *See* Order No. 888 at 31,693–94.

[13] *See id.*

[14] *See id.* at 31,694.

[15] *See Wisconsin Public Power Inc. SYSTEM.* v. *Wisconsin Public Service Corporation, et al.*, 83 FERC ¶61,198 (1998) [hereinafter *WPPI*].

[16] *See id.* at 61,857–58.

[17] *Id.* at 61,858.

[18] *See* Capacity Benefit Margin in Computing Available Transmission Capacity, 64 Fed. Reg. 16730–31 (March 31, 1999), 86 FERC ¶61,313 (1999), (hereinafter CBM Notice).

[19] The Electricity Consumers Resource Council and the American Iron and Steel Institute (Industrial Consumers), Docket No. EL99–46–000, written comments at 3 (footnote omitted).

In July 1999, the Commission issued an order clarifying the method for computing ATC, including provisions dealing with CBM.[20] There, the Commission stated that: ''[t]he measures that we are requiring transmission providers to take at this time consist of short-term solutions, which, for now, take no position on the transmission provider's ability to set aside CBM for generation reliability requirements.''[21] The Commission acknowledged that NERC had already started a process to establish a standardized methodology for deriving CBM, and directed public utility transmission providers, working through NERC, to complete this process by the end of 1999.[22]

NERC called on each region to develop and document its own methodologies and guidelines for determining TRM and CBM.[23] It reported that its ATC Working Group was continuing to develop CBM and TRM, and that the draft standards would require each region to develop a region-wide CBM methodology.[24] It also noted that many methods for calculating CBM were used by transmission providers within each region.[25] Although a single North American standard CBM method was called for by transmission customers, NERC reported that it was not able, at that time, to develop such a standard for CBM.[26] NERC noted that the consideration of a standard CBM method would follow the completion of regional methods,[27] a process that is still ongoing.

The lack of standards for TRM and CBM impedes the development of basic information required by Order Nos. 888 and 889 as a basis for eliminating undue discrimination in the provision of interstate transmission services. Further impeding competition is continued uncertainty about whether and how to account for CBM in determining ATC and how CBM costs should be allocated. The industry needs Commission guidance to achieve standardization in these areas.[28]

4. Transmission Curtailment Preference for Bundled Retail Load

The Commission continues to receive complaints that transmission service to deliver power to bundled retail customers continues to be superior to transmission services for wholesale and unbundled retail transmission customers. In *Northern States Power Company (NSP)*, the United States Court of Appeals for the Eighth Circuit held that the Commission had exceeded its authority when it rejected proposed transmission curtailment provisions, contained in a public utility's wholesale open access transmission tariff, that favored the utility's retail customers over its wholesale customers.[29] On remand, the Commission permitted NSP to amend its open access transmission tariff to reflect its proposed transmission curtailment procedures to be effective in the ''rare circumstances'' where generation redispatch is inadequate or unavailable to fully relieve the transmission constraint.[30] However, the Commission also told NSP that if it amends its tariff to reflect its proposed transmission curtailment procedures, ''NSP must revise its rates for firm point-to-point transmission service * * * to recognize the inferior quality of that service compared to the service provided by NSP to its native load and network customers. * * *''[31]

Although NSP later withdrew its objection to equal transmission curtailment treatment for all transmission customers, the case points out a difficulty the Commission has in ensuring transmission access that is not unduly discriminatory for all transmission customers—retail and wholesale—unless all transmission customers take service under the same tariff.

Seams Problems. Even apparently minor differences in rules can create seams problems. The three Northeastern ISOs, which have substantially similar market designs and transmission congestion management systems, have struggled to coordinate their rules to lower trading barriers, but have achieved only limited success after several years. If each RTO in the Nation were to implement different rules, processes, and market mechanisms, these differences combined could produce and exacerbate significant barriers to transmission and electric power sales in interstate commerce.[32]

As an example of a specific seams problem, incompatible ramping rules have made power sales among the ISO systems in the Northeast unnecessarily difficult and prevented some trades. Among the operating protocols of a transmission provider are rules for increasing and decreasing the power output of a generator (called ''ramping'') connected to the transmission system. To implement a transaction between two systems, generation in the supplying system must be increased, or ''ramped'' up, and generation in the receiving system must be decreased, or ''ramped'' down. The ramping up and ramping down in the two systems should begin at the same time, last for the same length of time, and end at the same time. But different systems can have different rules about the timing and rate of ramping. For example, PJM allows ramping to occur every fifteen minutes; it can occur, for example, at 1 p.m., 1:15 p.m., 1:30 p.m, 1:45 p.m., 2 p.m., and so forth. New York and New England require ramping to occur on the hour, at 1 p.m or 2 p.m. but not within an hour. Thus, PJM's ramping rules permit a sale from PJM to New York to begin on the half hour by ramping up generation in PJM, but New York's ramping rules do not allow a buyer in New York to receive the power because it cannot ramp down generation on the half hour. Also, systems may place different limits on the amount of ramping that may occur on the interface with a neighboring system. Then, one system may allow an amount to be exported that the neighbor will not allow to be imported.[33] These differences must be reconciled to maximize opportunities for constructive trade at minimal transaction costs and obstacles.

Several efforts are underway at the Commission or within the industry to address seams problems and the

[20] Capacity Benefit Margin in Computing Available Transmission Capacity, 88 FERC ¶61,099 (1999).

[21] *Id.* at 61,237. The order, among other things, also directed each transmission provider to post specific CBM information and practices on its OASIS site within 30 days of the order, and to reevaluate generation reliability needs periodically so as to make known the availability of CBM capacity to others. *See id.*

[22] *See id.* at 61,238.

[23] *See* Response of the North American Electric Reliability Council to the CBM Order, Docket No. EL99–46–000 (Aug. 12, 1999), at 3.

[24] *See id.* at 3–4.

[25] *See id.* at 5.

[26] *See id.*

[27] *See* Letter from Virginia C. Sulzberger, North American Electric Reliability Council, to David P. Boergers, FERC, Docket No. EL99–46–000 (Dec. 23, 1999), at 2. There have been no further Commission proceedings on a generic basis addressing CBM. Parties did raise the CBM issue in the proceedings leading to Order No. 2000, but the Commission determined that ''[t]hese issues are too detailed for this proceeding and we will not address them at this time.'' Order No. 2000 at 31,146. Development of methods for calculating ATC and CBM at NERC are continuing.

[28] Addressing the topic of ATC coordination, which includes the ''[p]roper quantification of transmission reliability margin (TRM)'' the NERC ATC Coordination Task Force concluded that:

The existing definition of ATC coordination does not meet the needs of all members of the marketplace (all market participants) because there are too many diverse opinions that will not allow for consensus. * * * It is impossible to meet the existing definition of coordination due to differing market objectives, and regional business practices and transmission provider tariffs, and corporate objectives. Until these issues are resolved, coordination will not occur. Available Transfer Capability Coordination Task Force, *ATC Coordination and Related Issues* at 8–9 (July 12, 2000), *available in ftp://www.nerc.com/pub/sys/all__upoll/pc/minutes/ac–0007m.pdf.*

[29] *Northern States Power Company, et al.* v. *Federal Energy Regulatory Commission,* 176 F.3d 1090, 1096 (8th Cir. 1999), *cert. denied sub nom.* Enron Power Marketing, Inc. v. Northern States Power Company, 528 U.S. 1182 (2000).

[30] *See* Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin), 89 FERC ¶ 61,178 at 61,552–53 (1999). Subsequently, the Commission has applied *NSP* narrowly and indicated that it continues to believe that it has the authority to treat such customers comparably. *See* North American Electric Reliability Council, *et al.,* 96 FERC ¶ 61,079 at 61,345 (2001).

[31] 89 FERC at 61,553.

[32] For perspectives on this topic and its possible economic consequences, *see* Mirant Corporation, *Northeast Power Markets: The Argument for a Unified Grid,* 139 Public Utilities Fortnightly, at 36–45, Sept. 1, 2001. See *also* Hartshorn, Andrew P. and Harvey, Scott M., Assessing the Short-Run Benefits from a Combined Northeast Market, LECG, LLC, October 23, 2001.

[33] An extensive list of seams issues, ISO rule differences, and a discussion of efforts to reduce seams problems among the Northeast systems is available at the ISO Memorandum of Understanding Web site. *See* Seams Issues—High Priority Items *http://www.isomou.com/working__ groups/business__practices/documents/general/bpwg__matrix.pdf*≤. At the June 12, 2002 Commission meeting, New York ISO presented a list of 40 seams issues in the Northeast and a time line for resolving these issues. *See* Transcripts of Commission Meetings, June 12, 2002, *available in http:www.ferc.gov/calendar/commissionmeetings/transcripts.htm.*

development of standards. The Commission issued a Notice of Proposed Rulemaking to standardize rules for interconnecting generators to the grid.[34] The Commission also issued an Advanced Notice of Proposed Rulemaking to extend the standardization requirements of Order No. 889 to include electronic scheduling, among other matters.[35] In response to the latter, the industry formed the Electronic Scheduling Collaborative (ESC) to develop recommendations for the proposed rule but reported that the diversity of business, operating and other practices around the country made it very difficult to develop standards and protocols for electronic scheduling that would apply to all public utility systems. In its October 5, 2001 report to the Commission, the Electronic Scheduling Collaborative identified ten key policy issues that would give significant impetus to standards development. All of these issues are addressed in this proposed rule. NERC is working to achieve more uniform and enforceable reliability rules, and the North American Energy Industry Standards Board was formed in the autumn of 2001 in part to develop standards for electric wholesale business practices and communications protocols. Regional groups have formed to address seams issues, including the Seams Steering Group for the Western Interconnection and a Memorandum of Understanding among the three Northeast ISOs and the Ontario Independent Market Operator to address seams issues. In the Midwest, over the last several years various groups have met to deal with seams issues between two or more proposed RTOs for the central United States. The Tennessee Valley Authority (TVA) has also negotiated memoranda of understanding with Midwest Independent System Operator, Entergy and Southern Companies to pursue development of a coordination agreement to address seams issues in the Southeast. In its RTO orders, the Commission has been concerned about seams between neighboring RTOs with different rules, and also about seams between entities that are part of one large RTO.[36]

Many panelists at the Commission's seams conference urged us to develop standards for RTOs before they begin operating—indeed before they invest heavily in software development for a unique set of regional transmission rules and market designs.[37] This urging played a significant role in the genesis of this rulemaking.

Another seams problem can arise from different market price mitigation rules in neighboring regions. When western electric power prices were high in 2001, for a short time the Commission applied price mitigation to certain generators in California for spot market sales of power within California.[38] But these mitigation measures did not apply to sales from these generators to buyers outside California. As a result, some California generators sold power to parties outside California, that sold the power back into the state without facing the same price mitigation rule, a practice that was dubbed ''megawatt laundering.'' The Commission shortly thereafter applied uniform mitigation measures throughout the United States portion of the Western interconnection to remedy this problem. Uniformity of rules eliminated the seams problem in that circumstance.[39]

Market Design Flaws. The ISO markets have experienced numerous design flaws. A few of the more fundamental flaws are detailed below:

1. *Transmission Congestion Pricing by Zones Rather than Nodes.* On all single utility transmission systems, the cost of congestion is allocated to all users of the grid on a load ratio share basis. ISOs have tried various ways to allocate these costs to the customer or customers whose transactions caused the congestion. Several ISO markets attempted to price transmission congestion based on the average cost of congestion for transfers of power between defined zones on the system, rather than pricing the transmission congestion on a point-to-point basis. The zonal method tries to allocate congestion costs without too much pricing complexity. The theory of the method is that zones can be established within which little transmission congestion will occur (if any congestion does occur within the zone, all customers receiving power within the zone must share the cost of congestion). Variants of zonal pricing were tried in California, PJM, Texas (ERCOT) and New England.[40] In all cases the methods contained a similar flaw: using the zonal price signal did not induce short-term efficiency in the region, and it spread the congestion costs too broadly to clearly identify the transactions causing the congestion or the location of the structural fixes necessary to resolve it. It has also been difficult to determine in advance the appropriate zones, as flows have changed after restructuring.[41]

2. *Overly Restrictive Ancillary Service Market Designs.* Although the specific designs were different, both the California ISO and ISO New England initially attempted to require sellers to separately bid into each of several ancillary services markets. The hope with this design was to establish vibrant markets for each of the various ancillary services. However, the market design did not allow the substitution of a higher quality product (operating reserve—spinning) for a lower quality product (operating reserve—supplemental), even if the higher quality product was available at a lower price. This resulted in thin markets for certain ancillary services because sellers had no incentive to offer in one market if another market paid more. The perverse result was that lesser quality product markets (such as operating reserve—supplemental) cleared at higher prices than higher quality products (operating reserve—spinning). Sellers had to guess, based on limited information, which service would be the most highly valued. The market design failed to recognize that certain ancillary services were substitutes, *e.g.*, spinning reserves can ''provide'' supplemental reserves because operating reserves—spinning are more responsive to the ISO's dispatch signal. This design flaw created artificial barriers to entry for certain products, increasing market power and inefficiency, causing customers to pay prices higher than necessary for ancillary services.[42]

3. *The Absence of a Day-Ahead Market.* Certain ISO markets, including PJM and ISO New England, began operations with only real-time energy markets. All prices for power sold through the balancing market and ancillary service markets were cleared based on schedules and actual purchases in real time. In all cases, ISOs with only a real-time market concluded that a day-ahead market settlement system was also needed so that transmission customers could better protect against congestion costs, and so buyers and sellers of energy too could better protect against energy price uncertainty.[43] A day-ahead market enhances reliability because it allows the system operator to assess the next day's likely load and available resources. The California ISO has had difficulty operating the system reliably since the California PX ceased operations. A financially binding day-ahead market serves a critical reliability function by facilitating planning, unit scheduling, and load balancing.

Appendix D—Conversion of the Order No. 888—A *Pro Forma* Tariff to the Revised Standard Market Design *Pro Forma* Tariff

The following outlines the Order No. 888–A *pro forma* tariff and indicates where the various sections appear in the SMD Tariff. Where there are modifications or additions, they are identified and described. In addition, throughout the SMD Tariff, we have revised our terminology to match the new NERC terminology.

[34] *See* Standardization of Generator Interconnection Agreements and Procedures, 62 Fed. Reg. 22,249 (May 2, 2002), FERC Stats. & Regs. ¶ 32,560 (2002).

[35] Open Access Same-Time Information System (Phase II), Docket No. RM00–10–000, Advance Notice of Proposed Rulemaking, 92 FERC ¶ 61,047 (July 14, 2000).

[36] *See* Alliance Companies, *et al.,* 97 FERC ¶ 61,327 at 62,530 (2001).

[37] Conference on RTO Interregional Coordination, Docket No. PL01-5-000, June 19, 2001.

[38] *See San Diego Gas & Electric Company* v. *Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange, et al.,* 95 FERC ¶ 61,115 (2001). The Commission's order on price mitigation provided in part that certain California generators that had not already sold their power were required to bid into the ISO's real-time market at a constrained bid price.

[39] *See* New York Independent System Operator, Inc., *et al.,* 92 FERC ¶ 61,073 (2000); *NSTAR Services Company* v. *New England Power Pool, et al.,* 92 FERC ¶ 61,065 (2000); and PJM Interconnection, L.L.C., 96 FERC ¶ 61,233 (2001) (orders accepting a uniform $1000 bid cap).

[40] *See* New England Power Pool, 88 FERC ¶ 61,147 (1999); PJM Interconnection, LLC, 81 FERC ¶ 61,257 (1997), *order on reh'g,* 92 FERC ¶ 61,282 (2000); Order Proposing Remedies for California Wholesale Electric Markets, 93 FERC ¶ 61,121 (2000).

[41] This zonal cost allocation for congestion management is different from and should not be confused with proposals to aggregate energy prices at several points into hubs.

[42] *See* AES Redondo Beach, L.L.C., *et al.,* 84 FERC ¶ 61,046 (1998); New England Power Pool, 85 FERC ¶ 61,379 (1998).

[43] *See* PJM Interconnection, LLC, 91 FERC ¶ 61,148 (2000); New England Power Pool, *et al.,* 96 FERC ¶ 61,317 (2001).

Order No. 888—A Pro Forma Tariff Table of Contents	SMD tariff location
I. COMMON SERVICE PROVISIONS	Part I
1 Definitions	A.1
[revised to include new transmission service, LMP, Congestion Revenue Rights, and market services]	
2 Initial Allocation and Renewal Procedures	revised
2.1 Initial Allocation of Available Transmission Capability	deleted
[the section was for the initial conversion to an open access tariff; it is no longer needed]	
2.2 Reservation Priority for Existing Firm Service Customers	B.12
[Revised to reflect transition to Congestion Revenue Rights. Ensures that existing customers keep the right to roll over long-term firm service until implementation of the Congestion Revenue Rights auction (B.12.1)]	
3 Ancillary Services	C
[Slight modification to definitions to match best practices of the Northeast ISOs]	
3.1 Scheduling, System Control and Dispatch Service	C.1
3.2 Reactive Supply and Voltage Control From Generation Sources Service	C.2
3.3 Regulation and Frequency Response Service	C.3
3.4 Energy Imbalance Service	C.4
[imbalances will be priced at real-time LMP price, making deviation band and delayed (30 days) resolution unnecessary]	
3.5 Operating Reserve—Spinning Reserve Service	C.5
3.6 Operating Reserve—Supplemental Reserve Service	C.5
4 Open Access Same-Time Information System (OASIS)	A.2
5 Local Furnishing Bonds	A.3
5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds	A.3.1
[reflects that Transmission Owner will not be the Transmission Provider; also modified to define the applicable provisions of the Internal Revenue Code; and to add language from the preamble of Order No. 888–A clarifying that this provision also applies if a customer requests service that would jeopardize the tax-exempt status of bonds used to finance the transmission provider's generation or distribution facilities, even if no transmission facilities were financed with such bonds]	
5.2 Alternative Procedures for Requesting Transmission Service	A.3.2
[modified to make transmission provider advise the customer of expected costs resulting from loss of tax-exempt status within thirty days of receipt of an application for service. Also modified to clarify that any Commission order issued pursuant to section 211 of the FPA would specify that service under this section is provided subject to the customer's payment of all costs deemed eligible for recovery]	
6 Reciprocity	A.4
7 Billing and Payment	A.5
7.1 Billing Procedure	A.5.1
7.2 Interest on Unpaid Balances	A.5.2
7.3 Customer Default	A.5.3
8 Accounting for the Transmission Provider's Use of the Tariff	deleted
[no longer needed as Transmission Provider is an independent entity—transmission owners that are load-serving entities will now take service under the revised tariff]	
9 Regulatory Filings	A.6
10 Force Majeure and Indemnification	A.7
10.1 Force Majeure	A.7.1
10.2 Indemnification	A.7.2
11 Creditworthiness	A.8
12 Dispute Resolution Procedures	A.10
12.1 Internal Dispute Resolution Procedures	A.10.1
12.2 External Arbitration Procedures	A.10.2
12.3 Arbitration Decisions	A.10.3
12.4 Costs	A.10.4
12.5 Rights Under the Federal Power Act	A.10.5
Additions to Part I of the Tariff	
(1.11) Eligibility for Transmission Provider Services	A.9
[replaces definition of Eligible Customer so that ''Customer'' could apply to transmission and market services]	
—Data and Confidentiality Provisions	A.12
[ensures that Transmission Provider and market monitoring unit have access to operational and bid data; additional changes to ensure Commission access to data for investigations]	
II. POINT-TO-POINT TRANSMISSION SERVICE	
[PTP service replaced by Network Access Service. Section replaced entirely (except as noted) by Network Access Service—many provisions here that are comparable to Network Integration Transmission Service retained]	
Preamble	
13 Nature of Firm Point-To-Point Transmission Service	
13.1 Term	B.2.2.1.(vi)
[modified to be as short as one hour of service]	
13.2 Reservation Priority	deleted
[first-come, first served priority system replaced with LMP, ''who values it the most'' system of rationing capacity]	
13.3 Use of Firm Transmission Service by the Transmission Provider	deleted
[''Transmission Provider'' will take service under a service agreement like all other customers]	
13.4 Service Agreements	B.2.5
[modified for Network Access Service]	
13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs	
13.6 Curtailment of Firm Transmission Service	deleted
[use NITS procedures]	

Order No. 888—A Pro Forma Tariff Table of Contents	SMD tariff location
13.7 Classification of Firm Transmission Service	
13.8 Scheduling of Firm Point-To-Point Transmission Service	B.2.10
[revised to incorporate scheduling through the Day-Ahead and Real-Time markets]	
14 Nature of Non-Firm Point-To-Point Transmission Service	deleted
[all scheduled service is firm under Network Access Service]	
15 Service Availability	
15.1 General Conditions	B.5.1
15.2 Determination of Available Transmission Capability	B.5.2
15.3 Initiating Service in the Absence of an Executed Service Agreement	B.2.9
15.4 Obligation To Provide Transmission Service That Requires Expansion or Modification of the Transmission System.	B.5.9
15.5 Deferral of Service	
15.6 Other Transmission Service Schedules	B.13
[modified to add service continues until contracts ''expire or'' are modified by the Commission]	
15.7 Real Power Losses	B.10.3.2
[revised to reference markets and cost of marginal losses]	
16 Transmission Customer Responsibilities	B.8
16.1 Conditions Required of Transmission Customers	B.8.1
16.2 Transmission Customer Responsibility for Third-Party Arrangements	B.8.2
17 Procedures for Arranging Firm Point-To-Point Transmission Service.	
17.1 Application	deleted
[Network Access Service will use comparable NITS procedures]	
17.2 Completed Application	B.2.2.1
[section retained with minor modifications in order and to establish minimum term of service of one hour; questions in preamble ask whether different procedures should be used by load-serving entity customers (who have load and/or generation and transmission facilities and need integration service) and non-load-serving entity transmission customers (who do not)]	
17.3 Deposit	B.2.2
17.4 Notice of Deficient Application	B.2.6
17.5 Response to a Completed Application	B.2.7
17.6 Execution of Service Agreement	B.2.8
17.7 Extensions for Commencement of Service	deleted
[related to PTP reservations which will not be used by Network Access Service]	
18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service	deleted
[all scheduled Network Access Service is firm]	
19 Additional Study Procedures for Firm Point-To-Point Transmission Service Requests	
19.1 Notice of Need for System Impact Study	B.5.3
19.2 System Impact Study Agreement and Cost Reimbursement	B.5.4
19.3 System Impact Study Procedures	B.5.5
19.4 Facilities Study Procedures	B.5.6
19.5 Facilities Study Modifications	B.5.7
19.6 Due Diligence in Completing New Facilities	B.5.8
19.7 Partial Interim Service	B.5.10
19.8 Expedited Procedures for New Facilities	B.5.11
20 Procedures if the Transmission Provider Is Unable To Complete New Transmission Facilities for Firm Point-To-Point Transmission Service.	B.6
20.1 Delays in Construction of New Facilities	B.6.1
20.2 Alternatives to the Original Facility Additions	B.6.2
20.3 Refund Obligation for Unfinished Facility Additions	B.6.3
21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities	B.7
21.1 Responsibility for Third-Party System Additions	B.7.1
21.2 Coordination of Third-Party System Additions	B.7.2
22 Changes in Service Specifications	
22.1 Modifications On a Non-Firm Basis	deleted
[use NITS procedures]	
22.2 Modification On a Firm Basis	deleted
[use NITS procedures]	
23 Sale or Assignment of Transmission Service	D.3, 7, and 8
[revised—replaced with the resale of Congestion Revenue Rights]	
24 Metering and Power Factor Correction at Receipt and Delivery Points(s)	A.11
24.1 Transmission Customer Obligations	A.11
[revised—additional detail added consistent with New York ISO Market Services Tariff]	
24.2 Transmission Provider Access to Metering Data	A.11
[revised—additional detail added consistent with New York ISO Market Services Tariff]	
24.3 Power Factor	A.11
[revised—additional detail added consistent with New York ISO Market Services Tariff]	
25 Compensation for Transmission Service	deleted
[charges based on NITS rates and charges instead (Section 34)]	
26 Stranded Cost Recovery	deleted
[the Transmission Provider is now an independent entity; recovery of stranded costs remains permissible, but will no longer be part of the tariff]	
27 Compensation for New Facilities and Redispatch Costs	deleted
[assignment of redispatch costs replaced by LMP system]	
III. NETWORK INTEGRATION TRANSMISSION SERVICE	

Order No. 888—A Pro Forma Tariff Table of Contents	SMD tariff location
[Replaced by Network Access Service; certain similar provisions retained and revised, as noted. Others added from PTP]	
Preamble	preamble
28 Nature of Network Integration Transmission Service	B.1
[revised to become Network Access Service]	
28.1 Scope of Service	B.1.1
28.2 Transmission Provider Responsibilities	B.1.3
28.3 Network Integration Transmission Service	deleted
[requires OATT service to be comparable to native load service; all service now the same by definition]	
28.4 Secondary Service	B.1.4
[revised to include Congestion Revenue Rights]	
28.5 Real Power Losses	B.10.3.2
[revised—losses can also be provided through the market]	
28.6 Restrictions on Use of Service	deleted
[no restrictions on service—third part sales must be PTP; now one service for all]	
29 Initiating Service	B.2
29.1 Condition Precedent for Receiving Service	B.2.1
29.2 Application Procedures	B.2.2.2
[section retained with minor modifications to establish minimum term of service of one hour; but questions in preamble ask whether different procedures should be used by load-serving entity customers (who have load and/or generation and transmission facilities and need integration service) and non-load-serving entity transmission customers (who do not)]	
29.3 Technical Arrangements To Be Completed Prior to Commencement of Service	B.2.3
29.4 Network Customer Facilities	B.2.4
29.5 Filing of Service Agreement	B.2.5
30 Network Resources	B.3
[section retained, but questions in preamble ask whether different procedures should be used by load-serving entity customers (who have load and/or generation and transmission facilities and need integration service) and non-load-serving entity transmission customers (who do not)]	
30.1 Designation of Network Resources	B.3.1
30.2 Designation of New Network Resources	B.3.2
30.3 Termination of Network Resources	B.3.3
30.4 Operation of Network Resources	B.3.4
30.5 Network Customer Redispatch Obligation	B.3.6
[redispatch obligation fulfilled through market structure—all generators will bid into market and follow Transmission Provider's dispatch instructions; section removes reference to Transmission Provider's own generation]	
30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With the Transmission Provider.	B.3.7
30.7 Limitation on Designation of Network Resources	deleted
[no limitations on amount of use of resources; any excess takes or deliveries priced at market clearing price]	
30.8 Use of Interface Capacity by the Network Customer	deleted
[customers can use as much interface capacity as they want as long as they are willing to pay congestion charges]	
30.9 Network Customer Owned Transmission Facilities	B.3.9
31 Designation of Network Load	B.4
[largely revised to remove the formal designation and replace with an identification of load and new loads]	
31.1 Network Load	B.4.1
31.2 New Network Loads Connected With the Transmission Provider	B.4.2
31.3 Network Load Not Physically Interconnected With the Transmission Provider	deleted
[required load on other systems to be counted as Network Load or served under PTP; now no charge for exports]	
31.4 New Interconnection Points	B.4.3
31.5 Changes in Service Requests	B.4.4
31.6 Annual Load and Resource Information Updates	B.4.5
32 Additional Study Procedures for Network Integration Transmission Service Requests	B.5
[now under Section 5, Service Availability. All sections modified to include requests for Congestion Revenue Rights]	
32.1 Notice of Need for System Impact Study	B.5.3
32.2 System Impact Study Agreement and Cost Reimbursement	B.5.4
32.3 System Impact Study Procedures	B.5.5
32.4 Facilities Study Procedures	B.5.6
33 Load Shedding and Curtailments	B.9
33.1 Procedures	B.9.1
[places curtailment procedures in the tariff rather than in Network Operating Agreements]	
33.2 Transmission Constraints	B.9.2
[narrows focus of section to address only constraints not first resolved by the LMP system]	
33.3 Cost Responsibility for Relieving Transmission Constraints	deleted
[load ratio share allocation of redispatch costs is replaced by LMP system]	
33.4 Curtailments of Scheduled Deliveries	B.9.3
[narrows focus of section to address only constraints not first resolved by the LMP system; gives priority to customers with adequate resources who are also using Congestion Revenue Rights (question in preamble on whether we should grant this priority)]	
33.5 Allocation of Curtailments	deleted

Order No. 888—A Pro Forma Tariff Table of Contents	SMD tariff location
[revised to no longer refer to sharing of curtailments between Transmission Provider and other customers—all load-serving entities will now be customers]	
33.6 Load Shedding	B.9.4
[provision in tariff, not Network Operating Agreement; done on a non-discriminatory basis]	
33.7 System Reliability	B.9.5
[Transmission Provider can propose penalties for failure to follow a curtailment order]	
34 Rates and Charges	B.10
34.1 Monthly Demand Charge	B.10.1
[revised to only apply the load ratio share Access Charge to deliveries to load located on the Transmission Provider's system; through and out service customers would not pay the Access Charge unless they wanted to receive a direct allocation of Congestion Revenue Rights]	
34.2 Determination of Network Customer's Monthly Network Load	B.10.2
[would only include load located on the Transmission Provider's system]	
34.3 Determination of Transmission Provider's Monthly Transmission System Load	deleted
[this section accounted for PTP service, which will no longer exist—may still need a transitional calculation]	
34.4 Redispatch Charge	B.10.3
[revised to describe the Usage Charge, which consists of the congestion charge and the loss charge]	
34.5 Stranded Cost Recovery	deleted
[the Transmission Provider is now an independent entity; recovery of stranded costs remains permissible, but will no longer be part of the tariff]	
35 Operating Arrangements	B.11
35.1 Operation under the Network Operating Agreement	B.11.1
35.2 Network Operating Agreement	B.11.2
35.3 Network Operating Committee	B.11.3
SCHEDULE 1	
Scheduling, System Control and Dispatch Service	C.1
SCHEDULE 2	
Reactive Supply and Voltage Control From Generation Sources Service	C.2
SCHEDULE 3	
Regulation and Frequency Response Service	C.3
SCHEDULE 4	
Energy Imbalance Service	C.4
SCHEDULE 5	
Operating Reserve—Spinning Reserve Service	C.5
SCHEDULE 6	
Operating Reserve—Supplemental Reserve Service	C.5
SCHEDULE 7	deleted
Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service	deleted
[all rates in Part VIII]	
SCHEDULE 8	deleted
Non-Firm Point-To-Point Transmission Service	deleted
[no non-firm service]	
ATTACHMENT A	
Form of Service Agreement for Firm Point-To-Point Transmission Service	Part VI
[name change for Network Access Service]	
ATTACHMENT B	
Form of Service Agreement for Non-Firm Point-To-Point Transmission Service	deleted
[no non-firm service]	
ATTACHMENT C	
Methodology To Assess Available Transmission Capability	Attachment A
[to be filed by Transmission Provider; must be done by an independent entity]	
ATTACHMENT D	
Methodology for Completing a System Impact Study	Attachment B
[to be filed by Transmission Provider]	
ATTACHMENT E	
Index of Point-To-Point Transmission Service Customers	Attachment D
[name change for Network Access Service]	
ATTACHMENT F	
Service Agreement for Network Integration Transmission Service	deleted
[one for all Network Access Service Customers—Part VI]	
ATTACHMENT G	
Network Operating Agreement	Attachment C
[to be filed by Transmission Provider]	
ATTACHMENT H	
Annual Transmission Revenue Requirement for Network Integration Transmission Service	Part VIII
[all rates addressed in Part VIII]	
ATTACHMENT I	
Index of Network Integration Transmission Service Customers	deleted
[one for all Network Access Service Customers—Attachment D]	
New Sections of the Pro Forma Tariff:	
Part II.D. Congestion Revenue Rights	
Part III. Day-Ahead and Real-Time Market Services	
Part IV. Market Monitoring	
Part V. Generation Interconnection Procedures	

Order No. 888—A Pro Forma Tariff Table of Contents	SMD tariff location
[will be the outcome of the Standardization of Generator Interconnection Agreements and Procedures, Notice of Proposed Rulemaking, 99 FERC ¶61,086 (2002)]	
Part VI. Transmission Planning and Expansion	
Part VIII. Appendices (Details for calculation of rates and market clearing prices)	

Appendix E

Standard Market Design and Trading Strategies Encountered in the Independent System Operators

Currently, five ISOs operate organized markets for energy and ancillary services, California ISO, PJM, New York ISO, ISO-New England and ERCOT. This appendix discusses how Standard Market Design would handle various trading strategies that were allegedly used for market manipulation in these ISOs, including those described by Enron Corporation in two memoranda as being used in the California wholesale markets. Standard Market Design incorporates lessons we have learned from experience in these organized markets. In many cases the proposed market rules have been designed to avoid the market design flaws that were the basis for these trading strategies. For others, Standard Market Design relies on strong market monitoring by the Independent Transmission Provider's Market Monitoring Unit and the Commission Office of Market Oversight and Investigation to ensure compliance with the market rules and to detect new market manipulation strategies.

Enron Strategies and Standard Market Design

In memoranda dated December 6, 2000 and December 8, 2000, attorneys for Enron detailed various trading strategies that were being used in California wholesale markets. The strategies discussed in the Enron memoranda were mainly tailored to take advantage of flaws in the California market design, particularly its congestion management system. Standard Market Design uses a different congestion management system that would make most of these strategies infeasible.

Most of the strategies described in the Enron memoranda depended on the development of a day-ahead schedule for power sales that was developed without determining whether that day-ahead schedule was physically feasible. In real time, the California ISO made payments to entities to relieve congestion. This created an incentive for an entity to create congestion in the day-ahead schedule at no cost so that the same entity would be paid to relieve that congestion in real time.

Standard Market Design uses a nodal congestion management system, Locational Marginal Pricing (LMP) together with a physically feasible and financially binding day-ahead schedule. The use of a nodal congestion management system ensures that all transmission constraints are considered in developing day-ahead schedules and any congestion is reflected in the prices for energy and transmission services.[1] Thus, there is no need to make separate payments in real time to relieve congestion in the day-ahead schedule, as there was in California. The day-ahead schedules under Standard Market Design would also be financially binding so that a marketer that changed its schedule in real time would still be financially liable for its day-ahead schedule. This also reduces the opportunities and incentives for market manipulation strategies that rely on differences between day-ahead and real-time prices.

A few of the strategies in the Enron memoranda appear to depend on the marketer providing false information to the ISO. Thus, these strategies rely on evading or violating the market rules rather than on market design flaws. Standard Market Design addresses these types of strategies by requiring an active market monitoring program that will detect violations of market rules and take appropriate action against entities that violate the market rules.

The specific strategies in the Enron memoranda are discussed below.

A. The Big Picture

1. ''Inc-ing Load'' (Fat Boy)—artificially increasing load on schedules submitted to the Cal PX; dispatching the generation as scheduled, which was in excess of actual load; being paid by the California ISO for the excess generation at the market clearing price.

This strategy appears to be designed to evade the requirement for balanced day-ahead schedules by the California ISO. Standard Market Design does not require load or generation to submit balanced day-ahead schedules. Therefore, such a strategy is not necessary to offer excess generation to the market. The market rules provide sellers with varying methods to do this. However, there are scheduling requirements and entities that do not follow them may be subject to penalties.

2. *Relieving Congestion*—creating congestion in the PX market (*i.e.,* the energy scheduled for delivery exceeds the capacity of the transmission path) and ''relieving'' such congestion in the real-time market. Accomplished by reducing schedules or scheduling transmission in the opposite direction, for which congestion payment is made by the ISO.

This strategy appears designed to exploit a flaw in the California market design that is not present in Standard Market Design. The day-ahead schedule for energy developed by the PX market did not take into account transmission constraints. As such, the schedule that was developed was often not physically feasible. Second, entities were then paid to relieve the congestion in real-time that resulted from the infeasible day-ahead schedule. In contrast, Standard Market Design uses a security constrained day-ahead schedule for energy. This means the day-ahead schedule accounts for all transmission system constraints needed for reliable system operations. Thus, the day-ahead schedules in the Standard Market Design will not have the type of manufactured congestion discussed in the Enron memoranda. Standard Market Design also uses a more efficient congestion management system, LMP, than that used by the California ISO. Under LMP, the entities that cause congestion are charged for that congestion. Thus, there would be no need for separate payments by the ISO to relieve congestion as occurred in California.

B. Representative Trading Strategies

1. Exports of California Power—buying energy for export and then importing that energy to evade the price caps in California.

The strategy was designed to take advantage of the fact that there was a price cap in effect in only part of the market. This problem was eliminated in California when West-wide mitigation measures were imposed. Standard Market Design will apply consistent market mitigation measures across all regions. Thus, the incentive for this type of strategy is significantly reduced. Also, Standard Market Design includes a resource adequacy requirement for load serving entities that avoids or minimizes the energy shortage conditions that made this strategy possible.

2. Non-firm Export—scheduling non-firm energy from a point in California to a control area outside of California and then cutting the non-firm energy after it receives payment for relieving congestion.

This strategy appears to exploit a loophole in the California congestion management system that allowed an entity to get a payment for shipping power that wasn't actually shipped. In contrast, under Standard Market Design the day-ahead schedule would be financially binding so a marketer could not cancel the arrangement without a financial penalty. Also, Standard Market Design uses LMP to manage congestion rather than separate payments to relieve congestion.

3. Death Star—scheduling energy in the opposite direction of congestion (counterflow) without putting energy onto or taking it off of the grid, yet still receiving congestion payments.

This strategy appears designed to exploit a flaw in the way that congestion charges were paid in California. Under LMP, the entity would only be paid in real time for power

[1] California used a zonal congestion management system that was designed to manage congestion between zones, but not within a zone. A nodal congestion management system is designed to manage congestion between any locations or nodes within the transmission system. In California, the day-ahead schedule for energy sales was developed by the PX and there was no requirement that this schedule be physically feasible

that actually flowed. Congestion charges would be computed as the difference between two locational energy prices under a LMP system rather than a separate charge as in California. This particular strategy also appears to depend on different congestion management systems being in effect in contiguous areas. That is, the California ISO's congestion charges did not reflect the availability of additional transmission capacity along a parallel path in an adjacent system. As long as that happens there likely are some opportunities for market manipulation. The long-term fix for this type of problem is a standard market design that applies to all areas within the market. Also, large regional organizations that cover natural markets will fix this problem. In Order No. 2000, the Commission encouraged the formation of these types of regional organizations.

4. Load Shift—submitting artificial schedules in order to receive inter-zonal congestion payments. Shifting load to receive congestion payments.

The strategy relies on the flaws in the congestion management system in California. The zonal congestion system used in California provides more opportunities to game congestion than the nodal congestion system under LMP. Because of the separation of the day-ahead market (formerly administered by the PX) and the real-time balancing market (administered by the ISO), there are numerous ways that market participants can create artificial congestion in the day-ahead market and then be paid to relieve the congestion in real time. Under LMP, the entity that caused the congestion would pay for the congestion.

5. ''Get Shorty''—paper trading of ancillary services. Enron has to submit false information to the CA ISO on the location of the plants to sell the ancillary services.

Standard Market Design proposes a day-ahead and real-time market for ancillary services. Financial bids for ancillary services are not permitted. Bidders would be required to identify specific units that would be used to provide the ancillary services. Market monitoring would be used to ensure that ancillary service bids are backed by real resources.

This strategy is also based on virtual bidding, something that is allowed under Standard Market Design for energy markets. Virtual bidding should cause the prices in the day-ahead and real-time markets to converge. This by itself does not harm customers. It means that a customer that buys power in real time will pay approximately the same as a customer that buys power day ahead. However, under Standard Market Design, bidders would be required to specifically identify energy bids that are not backed by physical resources. This is important for reliability purposes, to ensure that the transmission provider can ensure that sufficient physical resources are committed to meet the projected load. In contrast, Enron apparently indicated the ancillary bids were backed by physical resources when they were not. This could have affected reliability if Enron was actually called on to supply the ancillary services.

6. Wheel Out—scheduling a transmission flow while knowing that an intertie is completely constrained or that a line is out of service. Even though no energy is delivered, the trader will be paid a congestion charge for cutting the transaction.

This strategy appears designed to exploit two flaws in the California system that do not exist in Standard Market Design. First, because Standard Market Design uses security-constrained unit commitment and dispatch procedures in operating their energy markets, market participants could not schedule transactions day-ahead or real-time that are physically impossible. Second, the congestion management system under Standard Market Design is fully integrated with the energy markets and therefore would not provide separate payments for relieving congestion as in California. Under LMP, if more entities were trying to schedule an export than the physical capacity of the line, this excess would be reflected in the market clearing prices for the energy exports, which in turn would be used to compute appropriate congestion charges. Thus, there would be nothing to gain in using this strategy.

7. Ricochet—Buying energy from the Cal PX and exporting it to another entity which charges a small fee. The energy is resold in the real-time market.

The main purpose of this strategy is to evade California's price caps which apply to in-state generation, but not to external generation purchased ''out of market.'' Under Standard Market Design there would be consistent market mitigation measures across the country. Therefore, there would not be the opportunity to take advantage of the differences in market rules. In California, the ''Ricochet'' strategy ended when consistent West-wide mitigation rules went into effect.

8. Selling non-firm as firm—selling or reselling what is actually non-firm energy to the Cal PX but claiming that it is firm energy.

The reason for this strategy is that Enron would get paid for ancillary services if the energy was labeled as firm, but would not get paid for ancillary services if it was labeled as non-firm. Under Standard Market Design all transmission service would be under Network Access Service so there would be no difference in the ancillary service requirements. Thus, there would be no reason for this strategy.

9. Scheduling energy to collect congestion charge—scheduling a counterflow even though a company does not have any available generation. The entity is charged the real-time price for energy that it is short but receives a congestion payment for the scheduled counterflow. This activity is profitable whenever the congestion payment is greater than the charge associated with the energy that was not delivered.

This strategy exploited a loophole in the CA ISO congestion management system that does not exist under the LMP system used in Standard Market Design. As the memorandum notes, CA ISO paid congestion charges whether any power flowed or not. Under Standard Market Design if an entity sold energy in the day-ahead market it would either have to provide the energy in real time or buy back its position (it would be charged the real-time price for the energy). Also, the strategy may be related to the fact that the day-ahead schedule for energy developed by the Cal PX did not account for transmission constraints. CA ISO then paid congestion charges to entities to relieve the congestion they had created through their scheduling. The security constrained day-ahead schedules required in Standard Market Design takes into account transmission constraints. So, there is not the same opportunity for this type of market manipulation.

Market Manipulation in the Eastern ISO Markets: Implications for Standard Market Design

Because several components of Standard Market Design are based on market designs in effect in the Eastern ISOs markets—PJM, New York and New England—it is important to turn to these markets to verify that the Standard Market Design rules protect against market manipulation. In this regard, the following points are important. First, the Eastern ISO markets have recognized almost from the start of market operations that no market design can protect against market power due to structural conditions, such as the high concentration of firms in a region or load pocket and/or the lack of price-sensitive demand. For this reason, the Standard Market Design includes market power mitigation rules.

Second, there have been several years of learning in the Eastern ISO markets on market design. Small details of market design can turn out to have major effects on market performance. We have used this experience in developing the market rules for Standard Market Design.

Like the California markets, the Eastern ISO markets have been alleged to be subject periodically to physical and economic withholding of capacity by firms and other measures employed as a means to increase market prices for energy, ancillary services and installed capacity, and to manipulate the prices for transmission rights. However, these attempts have been more sporadic and have had a far less significant economic impact than California. This is due in part to the fact that approximately 85 percent of demand is covered under long-term contracts and therefore is unaffected by spot price volatility. In general, the Eastern markets are considered relatively competitive and have a range of measures in place to monitor and mitigate locational market power.[2] Several problematic markets, especially for installed capacity, have been eliminated or substantially modified. In addition, at least some types of market manipulation that have occurred in the New England market are associated with its interim market design,

[2] Each of the Eastern ISOs produces reports on market performance and on market power monitoring and mitigation. These reports are available on the ISO Web-sites; particular reports referenced in this section will be cited. In addition, filings before the Commission and Commission orders address these issues and will also be cited when referenced. *See also* FERC, ''Investigation of Bulk Power Markets: Northeast Region,'' November 1, 2000, available on the FERC web-site; State of New York Department of Public Service, ''Interim Pricing Report On New York State's Independent System Operator,'' Department of Public Service Pricing Team, December 2000.

and will not recur under the Standard Market Design. Similarly, in New York, many initial poor design decisions and software choices made within a framework similar to the proposed Standard Market Design have been modified and improved, yielding some lessons for future attempts to implement Standard Market Design markets.[3]

The previous section examined whether the Enron strategies in California could be used to manipulate prices under the Standard Market Design. This section reviews some of the publicly known examples of market manipulation in the Eastern ISO markets and discusses whether and how the Standard Market Design would prevent such activity.[4] The ISO market monitoring reports and filings before the Commission provide many further examples of market manipulation in the Eastern ISO markets that concern either minor events, transitory problems, or market rule changes made in anticipation of potential market manipulation. The Standard Market Design may not specifically require many of those rules, but the Commission will review Standard Market Design compliance filings to evaluate whether proposed market rules are susceptible to manipulation.

A. Energy Markets

The Eastern ISO energy markets have been subject to forms of market manipulation and market power, including both economic and physical withholding. Most exercise of market power in the energy markets occurs in two types of system conditions: (1) The existence of persistent transmission constraints in some locations and (2) periods of system-wide shortage of energy, such as exists on peak-load days or during emergencies. Locations that are on the import side of persistently congested transmission lines (sometimes called ''load pockets'') present the most opportunity for exercise of market power due to the high concentration that occurs in these locations. Generators in these locations are typically closely monitored and/or placed under contract to prevent bid price increases. Hence, this section will not consider market power in these locations.

During capacity shortages or system emergencies, market power is more diffuse, reflecting the possibility that all generation will have to be dispatched. For example, the PJM market monitor believes that high energy prices in the summer of 1999 were the result of the interaction of high demand levels with supply curves that exhibited steep slopes over very narrow ranges of output. Some firms appear to have withheld capacity and changed bid parameters during peak hours as a means to drive up prices (*see* discussion below). However, these prices also appear to have attracted imports into PJM. The market monitor thus concluded that the high prices were due both to scarcity and to the exercise of market power, but that the relative importance of the two factors could not be determined.[5]

During periods of shortage, interactions between the energy markets and the markets for ancillary services and installed capacity are also more significant. Market power in each type of market can affect the other. Price increases in the energy markets will lead to higher prices for ancillary services, since the prices in the latter markets reflect the opportunity costs associated with forgone energy sales.[6] Maintenance of the operating reserve requirement can also drive up prices in the energy market, because the ISO markets require that all energy should be taken to preserve the reserve margins prior to having to reduce them (see example 1(a), below); hence withholding of reserves could drive up not just reserve prices but also energy prices.[7]

1. Manipulation of physical bid parameters to extend the operating time or increase the output level of a generator and increase the market price—Several ISO markets have experienced firms' use of the bid-in physical parameters of generators, such as minimum run times and low operating levels, to extend the operating time and/or output of the generator and possibly set a higher market clearing price than was economically necessary. Typically, these problems are combined with specific market rules that allow the change in physical bid parameters to impact the price (under a purely competitive market assumption, changes in these parameters should not affect the price in the market). Two specific cases follow.

(a) In PJM, certain generators were increasing their minimum run times to the full 24 hours of the day and submitting high price bids. Under the PJM energy market rules, the bids were evaluated over the full day; hence, under normal conditions, high price bids would be rejected. However, in Maximum Generation Emergencies, PJM was required to take all economic offers, regardless of the number of hours of the day in which such offers were economic, prior to taking other emergency measures, such as recalling capacity resources. This allowed these generators to run at a high price all day and set LMPs higher than the $1,000 bid cap. PJM estimated that in 1999, excess energy payments to just one plant of $8 million resulted from this bidding technique. The Commission approved PJM's market rule revision to address this problem, which restricted the bid sufficiency guarantee only to the hours in which the generator bid was economic during the emergency.[8]

Under the proposed Standard Market Design market rules, as in PJM, a generator's bid offer must be considered over the full day. Hence in normal circumstances, as in PJM, changing the generator's minimum run time should not confer any competitive advantage. The Standard Market Design rules explicitly require that the Transmission Provider must evaluate how emergency conditions affect market prices. In complying with this requirement, the Commission will evaluate whether the rules prevent market manipulation, whether by adopting the PJM rules or some other measures.

(b) In New England, generators were bidding very high low operating levels—that is, setting a high minimum output level. By the existing rules in New England, these generators were not eligible to set the Energy Clearing Price but were eligible for uplift payments based on their bid. The ISO proposed, and the Commission accepted, that generators would be required to bid their physical low operating levels, subject to adjustment for emissions or economic efficiency reasons.[9] This kind of problem would be less likely in an LMP-based system with a revenue sufficiency guarantee.

Under Standard Market Design, the Transmission Provider is given authority to put limits on the frequency with which physical bid parameters can be changed, and other limits on how the operating characteristics of the generators are bid. These potential bid restrictions can be used to address any evidence of market manipulation or to anticipate such behavior.

B. Ancillary Service Markets

Bid-based ancillary service markets typically have fewer eligible suppliers (particularly until demand-side resources participate) than the energy markets as well as inelastic demand (unless demand curves for reserves are established). Locational reserve requirements may narrow the markets further. Finally, as noted above, market power in the energy markets is transferred to the ancillary service markets through opportunity cost payments and other market rules.[10] These factors make monitoring of these markets important. Under normal conditions, it is expected that regulation and operating reserves should account for under 10 percent of total market costs, and in the Eastern ISO markets are often under 5 percent. In contrast, in a few cases, poorly designed ancillary service markets and/or exercise of market power in these markets have resulted in ancillary services

[3] David B. Patton and Michael T. Wander, ''2001 Annual Report on The New York Electric Markets,'' Independent Market Advisor to the New York ISO, June 2002.

[4] Some paragraphs in this section are excerpted from FERC, ''Investigation of Bulk Power Markets: Northeast Region,'' November 1, 2000.

[5] PJM Market Monitoring Unit (MMU), ''PJM Interconnection State of the Market Report 1999,'' June 2000. The report explains that long-term net revenue results indicate that prices were competitive in 1999.

[6] The standard pricing rule for regulation and operating reserves is to compensate generators that would have been scheduled for energy but are withheld for regulation or reserves for the forgone energy revenues. This pricing rule is continued in the Standard Market Design.

[7] In addition to the example in 1(a), there are some significant instances in which the reliability rules that require ISOs to purchase energy from any external or internal source to maintain the reserve margin can increase the energy price. For example, prior to the imposition of the $1000 energy bid cap in the Eastern ISOs, ISO New England experienced an $6000/MWh energy clearing price for four hours in May 2000 due to an import purchase that was taken to avoid degrading the internal reserve margin. However, this case was not deemed to be exercise of market power. *See* FERC, ''Investigation of Bulk Power Markets: Northeast Region,'' November 1, 2000.

[8] *See* PJM Interconnection, L.L.C., 92 FERC ¶ 61,013 (2000).

[9] *See* ISO New England, Inc., 99 FERC ¶ 61,124 (2002).

[10] PJM Market Monitoring Unit (MMU), ''PJM Interconnection State of the Market Report 2001,'' PJM Interconnection, L.L.C., June 2002, p. 108.

temporarily accounting for a much higher percentage of total electricity costs.[11]

1. Withholding of Operating Reserves—The New York ISO markets for operating reserves experienced withholding of operating reserves in the Spring of 2000, resulting in substantially higher prices for these products for several months.[12] In particular, ten-minute non-spinning reserves were both withheld from the market physically or bid in at a high level by the three major suppliers. The high price for this reserve in turn drove up prices for regulation and the other operating reserves. In response, the Commission approved a bid cap on ten-minute non-spinning reserves and the New York ISO took additional measures to increase supply.[13] The Commission subsequently imposed a bid cap on non-spinning reserves in the ISO New England markets for similar reasons.[14] PJM delayed the start of a ten-minute spinning reserve market in part due to concerns about the potential for limited sellers of the product.

As in the energy markets, Standard Market Design auctions alone cannot solve structural sources of market power in the regulation and operating reserves markets. Rather, these problems must be addressed through a combination of market power mitigation measures, such as bid caps, and structural solutions, such as encouraging entry into these markets by generators with flexible start-times.

C. Congestion Management Systems and Transmission Rights

The congestion management system based on LMP and financial transmission rights proposed in the Standard Market Design and in use in PJM and New York presents a clear advantage over the transmission line-loading relief (TLR) methods used in other parts of the country. The LMP-based method has caused far fewer instances of transmission curtailments.[15] At the same time, any transmission network with congestion pricing and financial transmission rights is susceptible to some degree to market manipulation.[16] Heretofore, there has been some evidence of manipulation of these design elements in the Eastern ISO markets, although nothing that has disrupted the markets. Nevertheless, under Standard Market Design, such behavior will be monitored for and mitigated if found.

Care must be taken to discriminate between legitimate transactions and those aiming to favor owners of certain generation or transmission assets. Increasing congestion is not necessarily a sign of intentional activity to congest; all the Eastern ISOs report increasing congestion as market trading increases simply because there is more demand for distant resources and associated transmission. In addition, changes in congestion accounting may increase the amount of apparent congestion[17] and transmission maintenance or outages can also have a major effect.

An important financial linkage in the Standard Market Design is between the congestion management system and the holding of Congestion Revenue Rights. The Standard Market Design rules aim to find a method of allocation, trade and settlement of such rights that is equitable, transparent, provides appropriate incentives for maintenance of and investment in transmission assets, and is resistant to manipulation. The following example shows how market manipulation can occur.

1. Sharing of information about Transmission Maintenance by Transmission Owners to affect the value of affiliates holdings of Transmission Rights—In PJM, information acquired during a non-public investigation suggested that subsidiaries of Exelon, may have shared information that gave the marketing subsidiary an informational advantage in its bidding for Fixed Transmission Rights (FTRs) in the monthly FTR auctions. After the bidding closed in three auctions held in September, October, and November 1999, PECO announced maintenance outages on transmission facilities within PJM. The Commission directed Exelon, PECO and Exelon Power Team to show cause whether they violated section 205(b) of the Federal Power Act (FPA) and the standards of conduct and the Commission's regulations by operating PECO's transmission system in an unduly preferential manner or sharing non-public information regarding the timing and location of maintenance outages in PJM's system or both. The Commission also directed PJM to report, to the Commission on its current transmission oversight processes and procedures regarding maintenance and de-rating decisions.[18] PJM subsequently modified its transmission oversight procedures to eliminate incentives for such behavior.[19]

This problem is generic to electricity markets with transmission rights. The rights established under Standard Market Design, which include financial rights analogous to FTRs in PJM, are susceptible under some conditions to manipulation by transmission owners and their affiliates. The Standard Market Design requires market monitoring and appropriate transmission maintenance oversight and incentives to mitigate such problems.

D. Installed Capacity Markets

Each of the Eastern ISO markets has an installed capacity requirement and an ISO-operated capacity market (with the exception of New England, in which the market was terminated). The design of these markets is different in each ISO, as is the market structure (that is, the degree of firm concentration in the market); hence, the problems experienced in each market have also been different. As discussed in this proposed rule preamble (Section H), for various reasons the proposed Standard Market Design includes a resource adequacy requirement similar in purpose to what is called here ''installed capacity'' but does not include either specific rules for a tradable capacity product or a centralized market to provide such adequacy. However, regions may choose to establish such markets. This section discusses some of the market manipulation that has been experienced in the existing ICAP markets. The Commission will evaluate any proposals for new markets for resource adequacy on the basis that they do not result in a repeat of the flaws detected in the existing ISO installed capacity markets.

1. Bid Manipulation of poorly defined ICAP products (New England)—The original ISO New England ICAP market was recognized as a flawed market almost from its inception (along with other aspects of the New England markets),[20] but the true problems and attempts at market manipulation did not emerge until several months into operations. The basic flaw was that the ICAP product did not have any recall obligations or deliverability requirements and had only seasonal availability requirements. Hence, its value in the monthly auction was determined not by the value of ICAP but by the ability to manipulate the price. The auction clearing price tended to swing between $0/MW and very high prices. In early 2000, the ISO determined that the ICAP price was due to

[11] For example, New York ISO experienced one month, February 2000, in which regulation and operating reserves accounted for almost 30 percent of total market costs. This was an aberration due to the market power in the reserves markets discussed in example (1); following market power mitigation measures, the costs of these ancillary services dropped to under 5 percent of total market costs. *See* Patton, David B., ''New York Market Advisor Annual Report on The New York Electric Markets for Calendar Year 2000,'' ISO New York, April 2001, p. ix.

[12] *See id.*

[13] New York Independent System Operator, Inc., *et al.,* 91 FERC ¶ 61,218 (2000).

[14] *See* ISO New England, Inc., 99 FERC ¶ 61,124 (2002).

[15] *See, e.g.,* FERC, ''Investigation of Bulk Power Markets: Southeast Region,'' November 1, 2000; and FERC, ''Investigation of Bulk Power Markets: Midwest Region,'' November 1, 2000.

[16] Although electricity flows in complex patterns determined by physical laws and subject to the simultaneous interaction of all injections and withdrawals on the systems, the ways in which generators load certain lines can be calculated (through so-called ''generation shift factors'') or understood through experience.

[17] For example, PJM reports a notable increase in congestion over low-voltage facilities, which is at least in part associated with PJM assuming monitoring and control of these facilities from transmission owners. *See* PJM Market Monitoring Unit (MMU), ''PJM Interconnection State of the Market Report 2001,'' PJM Interconnection, L.L.C., June 2002, p. 126.

[18] *See* PJM Interconnection, L.L.C., 97 FERC ¶ 61,010 (2001).

[19] *See* PJM Interconnection, L.L.C. ''Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures, Docket No. EL01–122–000 (November 2, 2001).

[20] The preliminary New England market design was developed by NEPOOL committees over the course of 1998. Problems with this design were suggested by independent experts under contract to the ISO (*See* Peter Cramton and Robert Wilson, ''A Review of ISO New England's Proposed Market Rules,'' Report to ISO New England, Market Design Inc., September 1998). However, these experts, the ISO and NEPOOL supported beginning market operations and addressing market design problems with the markets in progress. NEPOOL proposed a phased implementation which was approved by the Commission. Market trials were run in January 1999 and the markets were started on May 1, 1999.

market power and revised the price for several months.

The subsequent modifications of the New England ICAP requirements and markets will not be reviewed here. In a June 28, 2000, order, the Commission agreed with the ISO that the existing installed capability auction market was not useful and that it could produce inflated prices unrelated to the actual harm created by installed capability deficiencies.[21] The Commission permitted the elimination of the auction market effective August 1, 2000, and required the ISO to revert to administratively-determined deficiency charge for failure to meet installed capability requirements.

2. Withholding of ICAP (PJM)—In the ICAP markets in PJM and New York, both structural problems and market design issues have resulted in ongoing refinement of market design and measures to limit the exercise of market power. An in-depth explanation of the designs of these markets is beyond the scope of this section; rather, the focus will be on the exercise of market power in the PJM daily capacity credit market in early 2001. The PJM market monitor has noted potentially high concentration and design flaws in this market since its inception on January 1, 1999, and there have been modifications of the market rules several times.

In PJM, each load-serving entity has the obligation to own capacity, have a bilateral contract for capacity, or purchase capacity credits through a centralized market equal to its peak load plus a reserve margin. To qualify as a capacity resource, a generating unit must pass tests regarding overall capability and the ability to deliver energy to PJM load, which requires adequate transmission capability. Load-serving entities can use their capacity resources to produce energy for export from the PJM control area, but such transactions are subject to recall by PJM in emergencies. If a load-serving entity's capacity resources are less than its obligation, then it is considered deficient and subject to a penalty. In 2001, the capacity credit market was operated on a daily, monthly and multi-monthly basis as well as on an ''interval'' basis defined by seasons (the daily market serves residual demand after the markets for longer-term credits close).

Between January and April 2001, a single firm raised the price in the daily capacity credit market for a sustained period of time by essentially being in a position that required all buyers that were short of capacity to have to purchase some or all of their capacity from it. The determination that this price increase was the exercise of market power through economic withholding was made on the basis of the excess capacity available at the time as well as calculation of the opportunity cost of that capacity, which is the sale of the firm energy output forward into a neighboring market. Effective June 2001, the Commission approved market rule changes that diminished the incentive to economically withhold by spreading the revenues accruing to owners of excess capacity to all compliant load-serving entities rather than to the single firm.[22]

Appendix F

Access Charges and Congestion Revenue Rights

Allocation of Congestion Revenue Rights

Phase I (Initial Allocation)—Through Direct Assignment Based on Historical Use

All existing customers using transmission service, whether through bundled contracts, service agreements under the *pro forma* tariff, or pre-Order No. 888 transmission contracts, pay the transmission rate, *i.e.*, the access charge, which enables the transmission owner to recover the fixed, or embedded, costs of its transmission system. Moreover, the existing *pro forma* tariff grants priority for transmission capacity to existing long-term firm customers.

This proposed rule gives the region a choice between an initial allocation or an auction of Congestion Revenue Rights. The first portion, ''Phase I,'' deals with regions that start with an allocation of Congestion Revenue Rights to existing long-term customers based on their historical use of the system. In this sense there is a link between paying the access charge and receiving Congestion Revenue Rights. However, this is not a one-to-one link, *i.e.*, not all customers paying the access charge will receive Congestion Revenue Rights—customers with short-term or non-firm service under the existing *pro forma* tariff currently pay an access charge but would receive no Congestion Revenue Rights through the initial allocation process. This is consistent with Section 2.2 of the existing *pro forma* tariff, which grants rollover rights (which guarantee access to firm service) only to longer-term contracts.

Phase I: Specific Examples—What the Customer Pays and What the Customer Gets

The following answers the question of whether and how the following customers currently receiving various services will pay access charges or receive Congestion Revenue Rights. All service in the following examples would be performed under Network Access Service upon implementation of Standard Market Design.

A. Short-Term and Non-Firm Contracts (less than one year in duration)

These customers would receive no Congestion Revenue Rights (however, transactions under which power is taken off the grid pay an access charge; those under which power is not taken off the grid do not pay an access charge). These contracts would be converted to Network Access Service at the time Standard Market Design is implemented through the SMD Tariff.

B. Long-Term Contracts (one year or longer)

1. Existing Network Integration Transmission Service—These customers currently pay and would continue to pay the access charge, and would receive a direct allocation of Congestion Revenue Rights.

2. Existing Point-to-Point Service.

a. Load-Serving Entity (service to load within a single Transmission Provider's area)—These customers currently pay and would continue to pay the access charge, and would receive a direct allocation of Congestion Revenue Rights.

b. Internal, Non-Load Serving Transactions (service within a single Transmission Provider's area from generator to hub, hub-to-hub, or to support sales to the spot market)—The customer currently has specific rights to capacity between stated points and, for this, pays the access charge. Under Standard Market Design, it would be permitted to retain its priority rights, albeit in the form of Congestion Revenue Rights rather than firm transmission capacity rights through Phase I. For this continued right, however, the customer must continue to pay the access charge to receive a direct allocation of Congestion Revenue Rights. In other words, it could choose to either (1) continue the point-to-point contract, including paying the access charge, and for that would receive a direct allocation of Congestion Revenue Rights; or (2) terminate the contract, meaning the customer would no longer pay the access charge, no longer receive specific transmission capacity rights between points, and, therefore, would not receive a direct allocation of Congestion Revenue Rights. Under the second choice, the customer would instead schedule service in the day-ahead and real-time markets and pay the applicable congestion and loss charges.

c. Through and Out (export by generator or marketer)—Consistent with internal, load-serving transactions (above), the customer currently has specific rights to capacity between stated points and, for this, pays the access charge, but would no longer be required to pay the access charge to export power to another region. It would be permitted to retain its priority rights, albeit in the form of Congestion Revenue Rights rather than firm transmission capacity rights through Phase I so long as it continued to pay an access charge on the source Transmission Provider's system. In addition, the access (or scheduling) charge paid by all load-serving entities taking power off of the grid on the sink side of a transaction involving two Transmission Providers' systems would include a portion of the transmission costs from the source side of the transaction, as explained below.

3. Existing Pre-888 Transmission Contract—These contracts are not standard and may have characteristics of Network Integration Transmission Service or Point-to-Point Transmission Service. Customers currently pay an access charge (though likely a different charge than under the *pro forma* tariff). In either case, the load-serving entity (the transmission owning public utility who currently is the transmission provider), would pay the Transmission Provider the access charge on behalf of the pre-888 customer, and would receive any direct allocation of the Congestion Revenue Rights associated with the contracts, unless the customer converted its contract to Network Access Service. Continued payment of the access charge and direct allocation of Congestion Revenue Rights would be based

[21] *See* ISO New England, Inc., *et al.,* 91 FERC ¶ 61,311 (2000).

[22] *See* PJM Interconnection, L.L.C., 95 FERC ¶ 61,175 (2001).

on the nature of the service and would be determined consistent with the pattern established above.

4. Bundled Wholesale Contract—Like pre-888 transmission contracts, these contracts are not standard and may have characteristics of Network Integration Transmission Service or Point-to-Point Transmission Service. Customers currently pay an access charge (though likely a different charge than under the *pro forma* tariff). Like the pre-888 contracts, the load-serving entity (the transmission owning public utility who currently is the transmission provider), would pay the Transmission Provider the access charge on behalf of the bundled wholesale customer, and would receive any direct allocation of the Congestion Revenue Rights associated with the contracts, unless the customer converted its contract to Network Access Service. Continued payment of the access charge and direct allocation of Congestion Revenue Rights would be based on the nature of the service and would be determined consistent with the pattern established above.

5. Bundled Retail Customers—There is no specific contract defining transmission rights for this type of service. Customers currently pay an access charge through the bundled rate. The load-serving entity, often the transmission owning public utility who currently is the transmission provider, would pay the Transmission Provider the access charge on behalf of the bundled retail customer, and would receive a direct allocation of the Congestion Revenue Rights.

6. Retail Choice—Customers in states with retail choice are either transmission customers under the *pro forma* tariff, or they are buying power from a supplier who is acting as the transmission customer on their behalf. They currently directly (or indirectly through the supplier) pay the access charge. The transmission customer in these transactions would receive the direct allocation of Congestion Revenue Rights. However, if the retail customer switched suppliers, this proposed rule establishes the principle that the Congestion Revenue Rights move with the load (*i.e.*, the Transmission Provider would have to periodically reallocate the Congestion Revenue Rights based on each load-serving entities' load ratio share).

Phase II (within four years of adoption of Standard Market Design)—Through an Auction

Under Phase II, Congestion Revenue Rights (other than those assigned to an entity on a ''life of the facility'' basis as a result of the customer paying for the network upgrades) will be auctioned off rather than allocated to particular customers. The link between paying the access charge and receiving Congestion Revenue Rights will no longer exist once we move to a full auction, since any entity can acquire Congestion Revenue Rights through the auction, with no requirement to pay an access charge to get them. Instead, the link moves to the revenue side, *i.e.*, the auction revenues would be returned to those customers paying the embedded costs of the system through an access charge.

Are There Differences in the Allocation of Congestion Revenue Rights Based on How the Rates Are Paid?

1. Service with rate based on open access tariff's embedded cost charge.

a. At the time of direct allocation—this is defined above (long-term customers pay the access charge and get the direct allocation of Congestion Revenue Rights)

b. At the time of the auction—this is defined above for various categories of customers (some customers will continue to pay the access charge, which will be reduced by auction revenues, but all Congestion Revenue Rights will be auctioned)

2. Service with rate based on incremental cost of new transmission facilities.

a. At the time of direct allocation—When a customer requests firm service under the existing *pro forma* tariff and network upgrades must, on occasion, be built to accommodate the service. The Commission has historically allowed rates for transmission service to be set at the higher of the incremental cost or the average embedded cost. Thus, the allocation of Congestion Revenue Rights for customers who are currently paying an incremental rate for transmission service will, therefore, be the same as for customers paying the embedded cost charge under the *pro forma* tariff for transmission service.

b. At the time of the auction—Under Standard Market Design, customers generally will no longer request to build facilities to receive ''firm'' service, since all service will be allocated based on the customer's willingness to pay congestion costs. Rather, customers will request an economic expansion in order to avoid paying the cost of congestion. For economic expansions that are not rolled in to the embedded cost charge, the customer will pay the Transmission Provider the cost of the new facilities in order to acquire the Congestion Revenue Rights, and will continue to pay the access charge to receive Network Access Service.

3. Economic Expansions—once an Independent Transmission Provider is in place, it (with state participation) would make a decision on pricing. Most likely, the beneficiary(ies) of the economic expansion of the network would pay for the cost of the new facilities in return for any Congestion Revenue Rights created by an increase in transfer capability, and will continue to pay the access charge to receive Network Access Service. Otherwise, all network expansions would be rolled in either regionally or to a license plate zone and, therefore, all newly created Congestion Revenue Rights would be auctioned.

4. Reliability Expansions.

a. At the time of direct allocation—reliability expansions benefit all users of the grid; therefore, the costs are rolled-in to the access charge either regionally or to a license plate zone. Accordingly, any newly created Congestion Revenue Rights associated with the expansion will be auctioned.

b. At the time of the auction—the introduction of the full auction would have no impact on reliability expansions, which will continue to be rolled-in either regionally or to a license plate zone with any newly created Congestion Revenue Rights associated with the expansion offered in an auction.

5. Generator that receives credits for network upgrades.

a. At the time of direct allocation—currently, the interconnecting generator pre-pays for transmission service and receives credits against the monthly cost of transmission service, whether the generator is the customer or it is chosen as a network resource by a load-serving entity. To the extent the generator is a long-term transmission customer, it would receive Congestion Revenue Rights associated with its transmission service (otherwise the network customer that chose the generator as a network resource would receive the Congestion Revenue Rights).[1] If participant funding is adopted, the customer would receive the Congestion Revenue Rights associated with the additional transfer capability made possible by the transmission expansion. This pricing is subject to the outcome of the Generator Interconnection proposed rule in Docket No. RM02–1–000.

b. At the time of the auction—a generator would be treated in the same fashion as other customers under the *pro forma* tariff both with respect to payment of the access charge and receipt of Congestion Revenue Rights. If participant funding is adopted, the customer would receive the Congestion Revenue Rights associated with the additional transfer capability made possible by the transmission expansion. This pricing is subject to the outcome of the Generator Interconnection proposed rule in [Docket No. RM02–1–000.

6. Merchant transmission owner.

a. At the time of direct allocation—A merchant transmission owner does not receive service, but rather is a transmission owner. A customer using this facility would also have to pay for service across the RTO plus a rate for service on the merchant facility. Accordingly, the merchant transmission owner would pay for the full cost of constructing the new facilities and would receive the Congestion Revenue Rights associated with its facility for the economic life of the facility. The full amount of those rights may be subject to change based on changes in the overall grid over time (*e.g.*, changes in flow patterns or deterioration of transfer capability of other lines may diminish the amount of Congestion Revenue Rights associated with the merchant facility).

b. At the time of the auction—the introduction of the full auction will not change the way merchant facilities are addressed—the merchant transmission owner would pay for the full cost of constructing the new facilities and would receive the Congestion Revenue Rights associated with its facility for the economic life of the facility.

[1] There could be situations where the transition to Network Access Service occurs prior to a customer receiving transmission credits it is entitled to. To the extent that such a customer would no longer be required to pay the access charge, we would expect the RTO or Independent Transmission Provider to return the remaining amounts to the customer at the same rate as if the current transmission charge were still in place until the balance is returned.

Cost Shifts Due to Eliminating the Access Charge for Inter-Regional Transfers

This rulemaking proposes to eliminate transaction fees (the access charge) on through and out transactions. This, by definition, raises the possibility of cost shifts, resulting in winners and losers. This scenario has been previously faced and resolved within a Transmission Provider's service area, with the result being the elimination of pancaked rates, and can be resolved across multiple service areas as well.

Currently, all transmission customers pay a share of the embedded costs of the transmission system. Under Standard Market Design, only load-serving entities (*i.e.*, customers taking load off of the grid) will pay a share of the embedded costs of the system through an access charge.[2] This means that the portion of embedded costs currently paid by customers transmitting power through or out of a Transmission Provider's service area must be picked up by load-serving entities. However, while this may seem like a rate increase, the benefits from the elimination of the interregional access charge should exceed the costs. Specifically, this occurs through the reduction in generation costs across the region, as we will explain below.

Current situation on a hypothetical RTO (or transmission provider's system): 90 percent of the embedded costs are paid for by bundled retail customers, network customers, and point-to-point customers who serve load within the RTO. 10 percent of the embedded costs are paid for by point-to-point customers exporting power to another RTO or moving power within the RTO but not to load.

Standard Market Design will have two transmission rate impacts: First, the non-load serving transactions will no longer pay the access charge. Second, the inter-regional transfers will be netted across RTOs and the load-serving entities on the net importing RTO will pay a load ratio share of the embedded costs of the exporting RTO. On first blush, it would appear that the load-serving entities on both RTOs will pay more of the embedded costs to make up for the fact that exporting generators will no longer pay an access charge. While this is true with respect to transmission costs, it ignores the intended benefit of this rate change—lower generation costs.

First, access charges paid by generators for the first leg of a transaction, whether to serve load in the same or a neighboring RTO, are ultimately paid by the purchaser of the power. So, recovering these costs directly from the load-serving entities will not increase the overall cost of delivered power.[3]

More importantly, removing this additional transaction fee reduces the cost of reaching generation on a neighboring RTO. The removal of the transaction cost makes cheaper generation available across a broader area, which leads to a more optimal dispatch and lower generation cost for all customers.

For example, assume load is served at a particular location in RTO A at an LMP of $25, and that there is a generator on neighboring RTO B willing and able to sell at $24 (*i.e.*, it has available capacity and there is no transmission constraint between the sink and source). However, RTO B has an access charge of $2, making the competing generator's delivered cost non-competitive at $26. Removing the $2 transaction fee reduces the generator's delivered cost to $24, saving all customers at that location $1, since the LMP is reduced from $25 to $24. Moreover, to the extent that other load within RTO A is served with generation cost in excess of $25, the $25 generator in RTO A that was displaced by the $24 generator in RTO B is now available to meet this load, providing greater generation savings across RTO A. Given that generation costs far exceed access charges, customers' overall savings (generation plus transmission costs) can be reduced far below the increase in transmission costs resulting from the elimination of the access charge on inter-regional transactions. There could be additional savings to the load-serving entities in that they would receive additional Congestion Revenue Rights (or the associated auction revenues) that would otherwise be held by the point-to-point customers.

The precise details of how current contracts will be transitioned and how embedded transmission costs associated with inter-regional transactions will be netted across regions should be left to regions to work out in compliance filings.

Appendix G

Security Standards for Electric Market Participants

Purpose

Wholesale electric grid operations are highly interdependent, and a failure of one part of the generation, transmission or grid management system can compromise the reliable operation of a major portion of the regional grid. Similarly, the wholesale electric market—as a network of economic transactions and interdependencies—relies on the continuing reliable operation of not only physical grid resources, but also the operational infrastructure of monitoring, dispatch and market software and systems. Because of this mutual vulnerability and interdependence, it is necessary to safeguard the electric grid and market resources and systems by establishing minimum standards for all market participants, to assure that a lack of security for one resource does not compromise security and risk grid and market failure for the market or grid as a whole.

The purpose of these standards is to ensure that electric market participants have a basic Security Program protecting the electric grid and market from the impacts of acts, either accidental or malicious, that aren't authentic or could cause wide-ranging, harmful impacts on grid operations and market resources. A basic Security Program for electric grid and market resources (hereafter referred to as market resources) shall cover governance, planning, prevention, operations, incident response, and business continuity.

Security standards for market resources will primarily focus on electronic systems, which include hardware, software, data, related communications networks, control systems as they impact the grid or market, and personnel (hereafter the word cyber shall refer to all of these aspects). In addition, physical security will be addressed to the extent that it is necessary to assure a secure physical environment for cyber resources.

This initial set of security standards represent a minimum set of measures derived from commonly accepted industry standards and practices, such as the Common Criteria, CTSEC, ITSEC, IPSEC, ISO 17799, NIST Guidelines, and the NERC Security Guidelines. Market participants are encouraged to review their individual situation and tolerance for risk and implement a Security Program that goes beyond these basic security standards herein.

Application

These standards are intended to ensure that appropriate mitigating plans and actions are in place, recognizing the role of the participant in the marketplace and the risks being managed. For the purpose of these security standards, participants are defined as, and the standards shall apply to:

- The market operations of RTO's and ISO's, and their market connections to Control Areas,
- Marketers,
- Transmission Owners,
- Power Producers,
- Load-serving entities and other power purchasers,
- NERC and the Reliability Authorities, and
- Tagging (or other similar dispatching) Organizations.

Further, if a power-generating unit participates directly in the grid (*i.e.*, it is electronically dispatched by control centers), the plant control system shall comply with these security standards. If a power-generating unit participates directly in the electric market (*i.e.*, submits tagging requests), its market systems shall also comply with these security standards.

Compliance

These security standards shall become effective on January 1, 2004. Beginning 2004, on January 1 of each year, every participant shall file with FERC a self-certification signed by an officer of the company indicating compliance with these standards and identifying any areas of non-compliance. Failure to comply with these security standards will result in loss of direct access privileges to the electric market.

Malicious acts directed against the electric market, shall be prosecuted by FERC and law enforcement agencies to the full extent of the law, including the recovery of damages.

Security Standards

Governance

Participant senior management shall designate a management official to be

[2] This may also include point-to-point customers who continue to pay the access charge to receive Congestion Revenue Rights.

[3] It is possible that there will be instances where a bundled purchase contract, if not reformed to reflect this change in transmission rate design, will result in the customer paying twice for transmission service. Affected customers could file under section 206 of the FPA to seek reformation of their contracts.

responsible for establishing and managing a basic Security Program for electric market functions and resources.

Security Scope

Participants shall define their security perimeter and identify the boundaries and defenses for physical and cyber security that delineate and protect the critical resources under their control. The security perimeter shall identify all entry and exit points and the requirements for access controls.

A Security Program and policy based on these security standards shall be developed to protect critical electric grid and market functions and resources within the security perimeter and at entry and exit points where personnel, supplies or communications may come and go. Additionally, related procedures shall be created that guide implementation and enforcement of the security standards. Policy and procedures shall be reviewed for appropriateness (due to changes in personnel, technology, equipment configuration, vulnerabilities and threats) as necessary, and at least annually.

Asset Classification and Control

Electric market assets within the security perimeter shall be classified as to their criticality in maintaining and protecting electric market functions. A classification system shall further define appropriate levels of protection for each level of criticality, and access rights that will be granted for each level of criticality. All critical assets within the perimeter (computers, networks, doorways, etc.) shall have a custodian who ensures that those assets are handled in accordance with their assigned classification scheme.

Personnel

Any personnel who are authorized access within the security perimeter, or are authorized access to administer, operate or maintain assets within the security perimeter shall be trained on the Security Program and security standards related to their respective positions. This training shall start upon employment, be repeated annually and at career points where significant responsibilities change. Security awareness training shall be provided to all staff.

To the extent permitted by law, personnel required to administer or operate assets classified as critical (according to the participant's classification system) shall undergo background investigation conducted prior to employment, upon promotion to such positions (if not a new hire), and at periodic intervals (not to exceed five years). The participant shall review the results of the background checks and take appropriate action. Individuals shall be disqualified from administering, operating or accessing critical assets if the individual meets any disqualifying criteria specified by the Federal Bureau of Investigation, Office of Homeland Security, RCMP, or other federal agency.

Access Control

A process such as transaction logs shall be in place to identify individual users of critical systems and their time of access. Procedures for critical electric grid and market resources within the security perimeter shall be developed that establish and monitor controls for:

(1) The assignment of both logical and physical access rights (as defined in the classification system);

(2) The prompt disabling of access rights when positions are terminated or job responsibilities no longer require access; and

(3) The annual re-evaluation of assigned access rights.

Such authorized personnel—including visitors and service vendors—shall only have access (whether logical or physical) to electric market resources within the security perimeter that they are authorized for. Any and all unauthorized personnel allowed temporary access within the security perimeter shall be escorted at all times.

Systems Management

Procedures for critical electric market resources within the security perimeter shall be developed to monitor and protect cyber assets, such as:

- Computers
- Software
- Data, as stored and transmitted
- Servers
- Routers
- Modems
- Communications channels, whether owned or leased

At a minimum, these procedures shall address:

(1) The use of effective password routines that periodically require changing of passwords, including the replacement of default passwords on newly installed equipment;

(2) Authorization and re-validation of computer accounts;

(3) Disabling of unauthorized (invalidated, expired) or unused computer accounts;

(4) Disabling of unused network services and ports;

(5) Secure dial-up modem connections;

(6) Firewall software (for routed Internet access);

(7) Intrusion Detection Systems (for networked routers and firewalls);

(8) Patch management;

(9) Installation and update of anti-virus software checkers.

For critical electric systems, operator logs and Intrusion Detection System logs shall be maintained for the purpose of checking system anomalies and for evidence of suspected unauthorized activity. Appropriate procedures for securing control systems that are critical to the grid or market shall be developed and employed. The procedures shall address:

(1) Remote access including modems and other means;

(2) Security patch management, as appropriate;

(3) Assurance that communication channels are adequate so as not to impact the performance of the control system and its critical functions; and

(4) Assurance that system procedures do not impact the performance of the control system and its critical functions.

Procedures for critical electric resources within the security perimeter shall be established to monitor and control physical features, such as:

- Doors,
- Windows,
- Floor space,
- Environmental systems,
- Backup power systems—whether owned or leased.

At a minimum, these procedures shall address:

(1) Appropriate security barriers and entry controls;

(2) Mechanical and electronic key and badge programs;

(3) Access locking of unattended assets; and,

(4) Protection from environmental threats and hazards (*e.g.*, loss of cooling).

Critical electric facilities shall restrict the distribution of maps, floor plans and equipment layouts pertaining to those facilities, and restrict the use of signage indicating critical facility locations.

Planning

Security requirements for critical electric systems within the security perimeter shall be identified, documented and agreed upon prior to development, procurement, enhancement to, installation of and acceptance testing for cyber resources or related physical features. For critical control systems, this means developing cyber security procedures to augment existing test and/or acceptance procedures.

Development and testing of critical electric market systems shall be conducted in system environments that are not interconnected with operational system environments.

Incident Response

Organizations with critical electric market resources shall have incident response procedures, which define roles, responsibilities and actions to rapidly detect and protect electric resources in the event of harmful or unusual incidents, whether accidental or malicious.

Organizations with critical electric market resources shall report incidents to the Electricity Sector—Information Sharing and Analysis Center (ES–ISAC) and use reporting criteria, thresholds and procedures contained in NERC's Indications, Analysis and Warning (IAW) Program.

Business Continuity

Every participant operating a critical electric resource shall have contingency plans that define roles, responsibilities and actions for protecting the rest of the electric grid and market from the failure of its own critical resources. Those plans should further define the roles, responsibilities and actions needed to quickly recover or reestablish electric grid and market functions, processes and systems, in the event that a critical physical or cyber resource fails or suffers harm or attack. Such plans shall be tested or exercised regularly.

References

The North American Electric Reliability Council (NERC) has established and maintains Security Guidelines for the Electricity Sector. NERC also provides a list of additional sources for security best practices. These references shall be helpful in developing organization-specific security standards and procedures for critical market resources.

BILLING CODE 6717–01–P

Annual Self-Certification of Compliance with FERC Security Standards (Due January 31, 2004, and every January 31st thereafter)

Date: ______________________

Subject: **FERC Filing, Annual Self-Certification re: FERC Security Standards**

From: ____(organization name)

____(organization address)

____(organization address)

____(organization address)

This organization certifies the following items regarding FERC security standards for grid-market systems, as of this date:

Compliant	Non-Compliant	Does Not Apply	
☐	☐	☐	Management assignment of grid-market system security.
☐	☐	☐	Security Perimeter defined and documented.
☐	☐	☐	Security Program and Policy developed and documented.
☐	☐	☐	Policy, standards, and procedures reviewed at least annually.
☐	☐	☐	An Asset Classification system defined and implemented.
☐	☐	☐	Security training requirements for personnel with access to critical assets have been met.
☐	☐	☐	All personnel receive security awareness training at least annually.
☐	☐	☐	Critical asset administrators and operators have had background

			screening within last five years.
☐	☐	☐	Access control procedures for authorized personnel are implemented.
☐	☐	☐	Unauthorized personnel inside security perimeter are escorted at all times.
☐	☐	☐	Cyber procedures for system security have been developed and implementation monitored for compliance.
☐	☐	☐	Physical procedures for system security have been developed and implementation monitored for compliance.
☐	☐	☐	Security requirements for developing and testing critical systems have been documented.
☐	☐	☐	Software development systems are not interconnected with operational systems.
☐	☐	☐	Incident response plans are implemented.
☐	☐	☐	ES-ISAC reporting and alert notification procedures are implemented.
☐	☐	☐	Business continuity plans are established and exercised.

Explanation for Non-Compliant Items:

Name: ______________________________(print)

______________________________(title)

______________________________(signature)

BILLING CODE 6717–01–C

Electricity Market Design and Structure

Breathitt, Commissioner, *concurring:*

I am writing separately on the Notice of Proposed Rulemaking (NOPR) on Standard Market Design (SMD) to express some of my thoughts on certain of its provisions and design elements. We have been discussing the broad contours of the SMD NOPR with interested parties for months through the staff white paper, the options paper and technical conferences. Many of the NOPR's features have been welcomed and embraced by various entities, associations, company representatives and academics. Just as many participants have cautioned us to make sure that the procedures, protocols and standards that we wish to impose on the industry we regulate are practical in implementation, fair to consumers and respectful of state jurisdiction. They have also asked us to recognize that not all regions of the country are the same or have the same historical ways of providing electricity to retail and wholesale customers.

For example, the way the Northeast has evolved with their power pools is vastly different from how the Southeast and the Southwest has traded bulk power. The northwest has a heavy reliance on hydroelectric generated power. Even with these differences, all the regions have provided reliable and steady service especially in times of extreme weather conditions.

People will be pouring over this NOPR to see if it is practical and if it is doable. During the October SMD/RTO week we were advised to keep it simple. This is anything but simple. It is a comprehensive proposal and it's very complicated. Over time it will result in a sophisticated market. Parties are going to need time to understand its complexities and implement its many features. The Commission is going to need patience and flexibility. We have not assigned a cost to this proposal but we know that each FERC jurisdictional entity is required to hire an independent transmission provider (ITP) if they are not already in an RTO. The ITPs must set up locational marginal pricing (LMP), day-ahead and real time energy markets, as well as ancillary services markets.

In Order 2000 we paired a voluntary rule with very tight compliance deadlines, deadlines that I believe we all knew at the time would be difficult to meet. Today's proposed rule pairs many complicated and mandatory requirements with short implementation time lines. For example, the LMP system paired with energy and ancillary services markets has not been proven outside of the tight power pools in the Northeast. Also, allocation of initial Congestion Revenue Rights will be complicated, if not problematic for some areas of the country. But, I am pleased that today's order recognizes that not all areas of the country will be able to move ahead with all requirements of SMD at lightning speed. The Commission intends to be flexible in some compliance dates and while it is the objective to have SMD in place within two years of the effective date of the Final Rule, the Commission will consider requests to extend that date.

The fundamental goal of SMD requirements in conjunction with the standardized transmission service is to create ''seamless'' wholesale power markets that allow sellers to transact easily across transmission grid boundaries. Once the final rule is in place and implemented my hope is that the squabbling over which entities belong in what RTO will end. We should be able to put our magic markers away for good.

Today's NOPR puts forward a detailed vision of the roles that ITPs, this commission and states will play in planning for expansion of the transmission grid. I am pleased that the governors have requested a significant role in transmission planning through the formation of Multi State Entities (or MSEs). I am also pleased that we propose to give MSEs a role in both overseeing the plans developed by the ITPs and in developing a fair pricing methodology for these expansions. I feel very positive about the bottom up approach that is described in the planning section of this NOPR. This approach allows merchant transmission companies and utilities, as well as generators and demand resources, to bring economic solutions to the table to solve the problems of under-built infrastructure. These projects must be vetted by the ITP to determine their impact on the grid in terms of loop flows and other regional impacts, but the real tests will be the demand for the projects much as we see in gas pipeline certificates.

I do have concerns about the planning protocols that would be enacted by the ITP once it is determined that economic projects cannot fulfill all of the reliability requirements of the grid. My concern is that this ''central planning'' aspect may direct projects that are uneconomic with costs socialized to all users of the grid. It is hard to imagine gold plating of the transmission grid when we are in an era of under-built infrastructure, but I believe that once we get the incentives right for building needed infrastructure there will be no need for the ITP to direct the construction of possibly ''uneconomic'' projects.

Getting the incentives right in grid expansion has been on my top ten list through this NOPR process and in my tenure here at the Commission. To this end, I have continued to be a proponent of Independent Transmission Companies (ITCs) and continue to believe that ITCs show great promise to address grid problems through profit driven activities. I am pleased that the NOPR proposes to adopt a form of participant funding once independent transmission entities are in place. I am also pleased that the Commission is willing to consider proposals submitted by Regional State Advisory Committees for participant funding prior to nation-wide adoption. This order gives a push to state and regional entities that already have significant momentum and I hope to see the fruit of the Regional-State groups efforts in the form of actionable plans for cost allocation of expanded transmission. However, if these groups have difficulty getting organized and implemented, there is a default mechanism that would allocate the costs of expanded transmission locally if the facilities are below 138 kV and regionally if the facilities are above the 138 kV level. I urge the parties, especially the states, to carefully consider this section of the NOPR and comment on this. I still have some uncertainty whether we reached the right balance here.

Furthermore, the states have been asking for some time for certain responsibilities in RTOs, particularly in the area of reliability and planning. In SMD it is envisioned that they will play important roles in developing the resource adequacy standards and transmission expansion pricing methods. We will give deference to areas that are not as far along in standardizing markets, allowing states to manage the pace of the required changes. Additionally, the proposed rule, while it asserts jurisdiction over native load, does not abrogate either actual or implicit contracts. I am not so Pollyanna as to believe that everyone will be happy with our assertion of jurisdiction over native load, in fact this is likely to be a big bone of contention. But take a look at the rule, as I think states will find that it tries to be balanced and allows them significant say in determining outcomes.

Another area that I have focused on in this process is cost shifts. I agree that embedded costs charges for wheel through and export transactions should be eliminated or minimized while at the same time assuring recovery of the transmission owner's revenue requirement. My concern with respect to cost shifts resulting from this removal of inter-regional rates is two-fold.

First, I fear that areas with low-cost energy, such as my state of Kentucky, will see those resources flow to high-cost areas located several states or regions away. It is a mathematical fact that when costs are averaged that someone's costs will go up. This particular concern is in part alleviated by the ability for those in low-cost areas to lock up their low-cost power resources in long term contracts. I also note that these transactions which will flow over greater distances, now that they no longer face the fixed cost of the transmission system, will be subject to marginal losses and congestion charges. I believe that marginal losses in excess of actual losses should be credited back to the areas where the power originated.

My second concern with cost shifts relates to the determination of how these costs will be apportioned among different types of customers. Even if costs are allocated to import zones instead of to each ITP, one customer in the zone that relies solely on generation within the zone could subsidize a customer that imports all of its requirements. This is due to the fact that the embedded costs for imports would be spread across all load within the zone. My hope is that parties will comment on these and other costs shifts giving us concrete examples of the kind and level of shifts that may occur. I would also ask for recommendations on how best to address cost shifts, especially if they have a significant impact on retail customers.

In Order 888, Imbalance service was an ancillary service that could be provided by the transmission provider or it could be self-supplied. In staff's initial thinking on SMD as expressed in their concept paper, the markets for both real-time and day ahead energy would only require voluntary participation. As we worked through the details of SMD, this idea morphed a bit to now require imbalance service to be taken through the real-time energy market set up by the ITP. Participation in the day-ahead market is still left to the buyer's discretion and bilateral contracts are encouraged. But, the requirement for load to buy their imbalance service through the real-time market is a significant change. Loads will be subject to spot prices for that small portion of their load that varies from their load forecasts. I hope that parties will comment on this change to imbalance service.

I believe that one of the fundamental underpinnings of this rule is to give equal access to the transmission grid to all and I support that notion. However, I recognize that giving everyone equal access means that decisions will be made based on each party's willingness to pay. This means that the price certainty that we gave through Order 888 will disappear. But, this does not mean that all price certainty will disappear because SMD provides mechanisms for customers to use to hedge the volatility in transmission markets and in real-time markets. My concern is that both small players and less sophisticated players will have increased transaction costs and steep learning curves in finding their way through these markets and in hedging these price risks. I don't want this rule to result in two classes of SMD participants—those that know how to participate effectively and those that have difficulty and incur higher costs without competitive benefits.

Also, after consulting several economic textbooks, we have defined market power for the first time in an electric order as ''the ability to raise price above the competitive level''. We caveat that definition by stating that the determination of when to intervene in a market, *i.e.* when the price is significantly raised for a sustained period, will be incorporated into our triggers for intervention rather that the definition. I am not positive that we have the definition right and I hope that parties will let us know if they think we have used the right definition.

The three prongs of mitigation proposed in this NOPR, local market mitigation, a safety-net bid cap, and the resource adequacy requirement, along with the requirement for an active independent market monitor should protect these markets during what could be a rocky inception. My hope is that over time there will be less reliance on mitigation measures as the structural problems in these markets subside. Further, I believe this proposed rule holds promise for solving the disagreements that we have today on the ability to exercise market power under our current methods for granting market-based rates. With these stringent new mitigation measures in place the Commission should reassess its reliance on the Supply Margin Assessment test and study the need for the 206 refund obligation.

With respect to governance, I do not agree with the level of prescription that we are imposing on certain governance proposals. I don't think the Commission should be dictating with such specificity so many rules concerning the explicit makeup of stakeholder committees, who can sit on which committees, and exactly how boards should be selected. This could have the effect of disbanding boards of RTOs that are in the formative stages and boards that might have met our Order 2000 independence requirements.

And last, but definitely not least, I am pleased that today's proposed rule keeps the same provisions for reciprocity as that of the OATT. Entities that already have waivers of the reciprocity provision will not have to come in again and request additional waiver from the SMD provisions. Today's proposed rule also would allow reciprocal OATTs to be grandfathered and require no further changes to those tariffs to meet the new SMD requirements. This provides necessary relief to small transmission owners, including municipalities and cooperatives.

I urge my colleagues to carefully consider the comments and not be shy about considering changes to the proposal. We are asking over seventy-five questions which indicates that we still need industry's and the public's advice on a number of issues. I will be anxiously awaiting the comments and look forward to what parties have to say on these and other issues.

Linda K. Breathitt,
Commissioner.

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