Access Charge A charge paid by all UDCs, MSSs and, in certain cases, Scheduling Coordinators, delivering Energy to Gross Load, as set forth in Section 7.1. The Access Charge includes the High Voltage Access Charge, the Transition Charge and the Low Voltage Access Charge. The Access Charge will recover the Participating TO's Transmission Revenue Requirement in accordance with Appendix F, Schedule 3. A Participating TO that has no transmission customers need not develop an Access Charge.

Actual Imbalance A deviation between scheduled Generation and metered Generation at each UDC/ISO Controlled Grid boundary or at each Participating Generator's delivery point or a deviation between scheduled Load and metered Load at each UDC/ISO Controlled Grid boundary or ISO Control Area boundary.

Administrative Price	The price set by the ISO in place of a Market Clearing Price when, by reason of a System Emergency, the ISO determines that it no longer has the ability to maintain reliable operation of the ISO Controlled Grid relying solely on the economic Dispatch of Generation. This price will remain in effect until the ISO considers that the System Emergency has been contained and corrected.
Affiliate	An entity, company or person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with the subject entity, company, or person.
AGC (Automatic Generation Control)	Generation equipment that automatically responds to signals from the ISO's EMS control in real time to control the power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other, so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits.

Aggregate Final Accepted Schedules	ISO approved aggregated Final Schedules.
Alert Notice	A Notice issued by the ISO when the operating requirements of the ISO Controlled Grid are marginal because of Demand exceeding forecast, loss of major Generation, or loss of transmission capacity that has curtailed imports into the ISO Control Area, or if the Hour-Ahead Market is short on scheduled Energy and Ancillary Services for the ISO Control Area.
Allocated Start-Up Costs	Allocated Start-Up Costs has the meaning set forth in Section 5.12.7.1.1.2.
Ancillary Services	Regulation, Spinning Reserve, Non-Spinning Reserve, Voltage Support and Black Start together with such other interconnected operation services as the ISO may develop in cooperation with Market Participants to support the transmission of Energy from Generation resources to Loads while maintaining reliable operation of the ISO Controlled Grid in accordance with Good Utility Practice.
Ancillary Service Marginal Price	The marginal cost of providing the respective Ancillary Service in the relevant Ancillary Service Region.
Ancillary Service Region	A group of adjoining Load Zones for which Ancillary Service requirements are jointly determined.
Ancillary Service Provider	A Participating Generator or Participating Load who is eligible to provide an Ancillary Serviced.
Applicable Reliability Criteria	The reliability standards established by NERC, WSCC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC.

Applicants Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and any others as applicable.

Available Transmission Capacity	For a given transmission path, the capacity rating in MW of the path established consistent with ISO and WSCC transmission capacity rating guidelines, less any reserved uses applicable to the path.
Balanced Schedule	A Schedule shall be deemed balanced when Generation equals forecast Demand with respect to all entities for which a Scheduling Coordinator schedules.
Balancing Account	An account set up to allow periodic balancing of financial transactions that, in the normal course of business, do not result in a zero balance of cash inflows and outflows.
Base Transmission Revenue Requirements	The Transmission Revenue Requirement adjusted to reflect the Transmission Revenue Balancing Account Adjustment (TRBAA).
Bid Cap	A limit on a bid price, either a Bid Ceiling or a Bid Floor.
Bid Ceiling	The maximum price permitted for a bid.
Bid Floor	The minimum price permitted for a bid.

Black Start	The procedure by which a Generating Unit self-starts without an external source of electricity thereby restoring power to the ISO Controlled Grid following system or local area blackouts.
Black Start Generator	A Participating Generator in its capacity as party to an Interim Black Start Agreement with the ISO for the provision of Black Start services, but shall exclude Participating Generators in their capacity as providers of Black Start services under their Reliability Must-Run Contracts
Bulk Supply Point	A UDC metering point.
Business Day	A day on which banks are open to conduct general banking business in California.
Capacity Resource	A resource that is required to offer available capacity to the ISO Markets either because (1) it is required to do so as set forth in Section 31.2.3.2.2 of this Tariff or (2) it is required to do so in accordance with a contractual obligation it has with a Load Serving Entity.
C.F.R.	Code of Federal Regulations.
Completed Application Date	For purposes of Section 5.7, the date on which a New Facility Operator submits an Interconnection Application to the ISO that satisfies the requirements of the ISO Tariff and TO Tariff of the Interconnecting PTO.
Completed Interconnection Application	An Interconnection Application that meets the information requirements as specified by the ISO and posted on the ISO Home Page.
Conditional Energy Bids	A Bid for Energy to serve Demand at or below a specified price.
Congestion	A condition that occurs when there is insufficient Available

Transmission Capacity to implement all Preferred Schedules simultaneously or, in real time, to serve all Generation and Demand. "Congested" shall be construed accordingly.

Congestion Management The alleviation of Congestion in accordance with Applicable ISO Protocols and Good Utility Practice.

Congestion Revenue The difference between charges to Demand and payments to Supply in the Day-Ahead and Hour-Ahead Energy Settlements, including explicit Congestion charges for intertie transmission capacity reservation for Day-Ahead Ancillary Service imports. Congestion Revenue also includes the marginal cost of transmission losses.

Connected Entity A Participating TO or any party that owns or operates facilities that are electrically interconnected with the ISO Controlled Grid.

Constraints Physical and operational limitations on the transfer of electrical power through transmission facilities.

Contingency Disconnection or separation, planned or forced, of one or more components from an electrical system.

Control Area An electric power system (or combination of electric power systems) to which a common AGC scheme is applied in order to: i) match, at all times, the power output of the Generating Units within the electric power system(s), plus the Energy purchased from entities outside the electric power system(s), minus Energy sold to entities outside the electric power system, with the Demand within the electric power system(s); ii) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and iv) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Area Gross Load For the purpose of calculating and billing the Grid Management Charge, Minimum Load Costs, Emissions Costs Charge and Start-Up Fuel Costs Charge, Control Area Gross Load is all Demand for Energy within the ISO Control Area. Control Area Gross Load shall not include Energy consumed by:

(a) generator auxiliary Load equipment that is dedicated to the production of Energy and is electrically connected at the same point as the Generating Unit (*e.g.*, auxiliary Load equipment that is served via a distribution line that is separate from the switchyard to which the Generating Unit is connected will not be considered to be electrically connected at the same point); and

(b) Load that is isolated electrically from the ISO Control Area (*i.e.*, Load that is not synchronized with the ISO Control Area).

Control Area Services Charge — The component of the Grid Management Charge that provides for recovery of the ISO's costs of ensuring safe, reliable operation of the transmission grid and dispatch of bulk power supplies in accordance with regional and national reliability standards, including, but not limited to:

- performing operation studies;
- system security analyses;
- transmission maintenance standards;
- system planning to ensure overall reliability;
- integration with other Control Areas;
- emergency management;
- outage coordination;
- transmission planning; and
- scheduling generation, imports, exports, and wheeling in the Day-Ahead and Hour-Ahead of actual operations.

Converted Rights — Those transmission service rights as defined in Section 2.4.4.2.1 of the ISO Tariff.

Cost Shifting — A transfer of costs from one group of customers to another or from one utility to another.

CPUC — The California Public Utilities Commission, or its successor.

Critical Protective System	Facilities and sites with protective relay systems and Remedial Action Schemes that the ISO determines may have a direct impact on the ability of the ISO to maintain system security and over which the ISO exercises Operational Control.
CTC (Competition Transition Charge)	A non-bypassable charge that is the mechanism that the California Legislature and the CPUC mandated to permit recovery of costs stranded as a result of the shift to the new market structure.
Curtailable Demand	Dispatchable Load that can only be reduced.
Customer Aggregation	A customized aggregation of end-use Loads served by a Load Serving Entity (LSE), which the LSE designates for scheduling and Settlement as an alternative to the Standard Aggregation.
Data Adequacy Requirement	Any applicable minimum data requirements of the state agency responsible for generation siting or of any Local Regulatory Authority.
Day-Ahead	Relating to a Day-Ahead Market or Day-Ahead Schedule.
Day-Ahead Market	The forward market for Energy and Ancillary Services to be supplied during the Settlement Periods of a particular Trading Day that is conducted by the ISO, the PX and other Scheduling Coordinators and which closes with the ISO's acceptance of the Final Day-Ahead Schedule.
Day-Ahead Schedule	A Schedule prepared by a Scheduling Coordinator or the ISO before the beginning of a Trading Day indicating the levels of Generation and Demand scheduled for each Settlement Period of that Trading Day.

Delivery Point	The point where a transaction between Scheduling Coordinators is deemed to take place. It can be either the Generation input point, a Demand Take-Out Point, or a transmission bus at some intermediate location.
Delivery Upgrade	The transmission facilities, other than Direct Assignment Facilities and Reliability Upgrades, necessary to relieve constraints on the ISO Controlled Grid and to ensure the delivery of energy from a New Facility to Load.
Demand	The rate at which Energy is delivered to Loads and Scheduling Points by Generation, transmission or distribution facilities. It is the product of voltage and the in-phase component of alternating current measured in units of watts or standard multiples thereof, e.g., 1,000W=1kW, 1,000kW=1MW, etc.
Demand Bid	A bid indicating a quantity of Energy that an Eligible Customer wishes to purchase and, if relevant, the maximum price that the customer is prepared to pay for that Energy. This bid will only be accepted if the Locational Marginal Price is at or below the price of the Demand Bid. A Buyer may state, for each hour, a different price preference for each demand quantity in each location, i.e., the maximum price in each hour at which it is prepared to take a specified amount of Energy in the Day-Ahead Schedule. If a bid is submitted without a price, it is assumed that the bidder is prepared to pay the Locational Marginal Price.
Demand Forecast	An estimate of Demand over a designated period of time.
Demand Market Participant	Any Eligible Customer on behalf of whom Demand and Ancillary Services are scheduled pursuant to the ISO Tariff.

Direct Access Generation	An Eligible Customer who is selling Energy or Ancillary Services through a Scheduling Coordinator.
Direct Assignment Facility	The transmission facilities necessary to physically and electrically interconnect a New Facility Operator to the ISO Controlled Grid at the point of interconnection.
Dispatch	The operating control of an integrated electric system to: i) assign specific Generating Units and other sources of supply to effect the supply to meet the relevant area Demand taken as Load rises or falls; ii) control operations and maintenance of high voltage lines, substations, and equipment, including administration of safety procedures; iii) operate interconnections; iv) manage Energy transactions with other interconnected Control Areas; and v) curtail Demand.
Dispatch Instruction	An instruction by the ISO to a resource for increasing or decreasing its energy supply or demand from the Hour-Ahead Schedule to a specified operating point.
Dispatch Interval	The time period, which may range between five (5) and thirty (30) minutes, over which the ISO's SCED software measures deviations in Generation and Demand, and selects Ancillary Service and Supplemental Energy resources to provide Imbalance Energy in response to such deviations. Following a decision, by the ISO Governing Board, the ISO may, by seven (7) days' notice published on the ISO's Home Page, at http://www.caiso.com (or such other internet address as the ISO may publish from time to time), increase or decrease the Dispatch Interval within the range of five (5) to thirty (30) minutes.

Dispatch Operating Point	The expected operating point of a resource that has received a Dispatch Instruction. The resource is expected to operate at the Dispatch Operating Point after completing the Dispatch Instruction, taking into account any relevant ramp rate and time delays. Energy expected to be produced or consumed above or below the Final Hour-Ahead Schedule in response to a Dispatch Instruction constitutes Instructed Imbalance Energy. For resources that have not received a Dispatch Instruction, the Dispatch Operating Point defaults to the corresponding Final Hour-Ahead Schedule.
Dispatchable Load	Load that can be curtailed or increased at the direction of the ISO in the real time dispatch of the ISO Controlled Grid, in a measurable and verifiable manner within specified time limits, and that meet standards adopted by the ISO and published on the ISO Home Page.
Distribution System	The distribution assets of a TO or UDC.
EEP (Electrical Emergency Plan)	A plan to be developed by the ISO in consultation with UDCs to address situations when Energy reserve margins are forecast to be below established levels..
Electric Capacity	The continuous demand-carrying ability for which a Generating Unit, or other electrical apparatus is rated, either by the user or by the manufacturer.

Energy	The electrical energy produced, flowing or supplied by generation, transmission or distribution facilities, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh=1kWh, 1,000 kWh=1MWh, etc.
Energy Bid	The price at or above which a resource has agreed to produce or the price at or below which a resource has agreed to consume the next increment of Energy.
Energy Efficiency Services	Services that are intended to assist End-Users in achieving savings in their use of Energy or increased efficiency in their use of Energy.
Entitlements	The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.
Environmental Dispatch	Dispatch designed to meet the requirements of air quality and other environmental legislation and environmental agencies having authority or jurisdiction over the ISO.
Environmental Quality	In relation to Energy, means Energy which involves production sources that reduce harm to the environment.
Equipment Clearances	The process by which the ISO grants authorization to another party to connect or disconnect electric equipment interconnected to the ISO Controlled Grid.
Exceptional Dispatch	Dispatch other than the Dispatch determined by SCED.

Final Hour-Ahead Schedule	The Hour-Ahead Schedule of Generation and Demand that has been approved by the ISO as feasible and consistent with all other Schedules based on the ISO's Hour-Ahead Congestion Management procedures.
Final Schedule	A Schedule developed by the ISO following receipt of a Preferred Schedule from a Scheduling Coordinator.
Final Settlement Statement	The restatement or recalculation of the Preliminary Settlement Statement by the ISO following the issue of that Preliminary Settlement Statement.
Flexible Generation	Generation that is capable of, and for which the Generator has agreed to, adjust operating levels in response to real time market price or ISO control signals.
Forced Outage	An Outage for which sufficient notice cannot be given to allow the Outage to be factored into the Day-Ahead Market or Hour-Ahead Market scheduling processes.
FPA	Parts II and III of the Federal Power Act, 16 U.S.C. § 824 et seq., as they may be amended from time to time.
FTR (Firm Transmission Right)	A contractual right, subject to the terms and conditions of the ISO Tariff, that entitles the FTR Holder to receive, for each hour of the term of the FTR, a portion of the Usage Charges received by the ISO for transportation of energy from a specific originating Zone to a specific receiving Zone and, in the event of an uneconomic curtailment to manage Day-Ahead congestion, to a Day-Ahead scheduling priority higher than that of a schedule using Converted Rights capacity that does not have an FTR.

FTR Holder The owner of an FTR, as registered with the ISO.

FTR Market A transmission path from an originating Zone to a contiguous receiving Zone for which FTRs are auctioned by the ISO in accordance with Section 9.4 of the ISO Tariff.

Full Network Model A network model that includes all network nodes and transmission facilities in the ISO Controlled Grid and a reduced external equivalent network for external systems.

Generating Unit An individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered or a Physical Scheduling Plant that, in either case, is:

(a) located within the ISO Control Area;

(b) connected to the ISO Controlled Grid, either directly or via interconnected transmission, or distribution facilities; and

(c) that is capable of producing and delivering net Energy (Energy in excess of a generating station's internal power requirements).

Generation Energy delivered from a Generating Unit.

Generation Dispatch Constraints	Details of any mandatory Generating Unit commitment requirements (e.g., Must-Run Generation) or dispatch limits (minimum output or maximum output) that must be observed due to system operating constraints (e.g., thermal, voltage, or stability limits). These limits are in addition to limits that may be specified by Generators in their Energy or Ancillary Service bids to the ISO.
Generation Scheduling	The ISO's planned hourly pattern of Generation.
Generator	The seller of Energy or Ancillary Services produced by a Generating Unit.
Good Faith Deposit	The deposit paid to the ISO by a New Facility Operator with submission of its Interconnection Application in accordance with Section 5.7.3.2, in an amount equal to $10,000, including any interest that accrues on the original amount, less any bank fees or other charges assessed on the escrow account. A New Facility Operator may satisfy its deposit obligation through any commercially available financial instrument determined to be satisfactory by the ISO.
Good Utility Practice	Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the

Grid Management Charge The ISO monthly charge on all Scheduling Coordinators and other appropriate parties that provides for the recovery of the ISO's costs through the three service charges described in Section 8.3: 1) the Control Area Services Charge, 2) the Inter-Zonal Scheduling Charge, and 3) the Market Operations Charge. The three component charges are formula rates.

Gross Load For the purposes of calculating the transmission Access Charge, Gross Load is all Energy (adjusted for distribution losses) delivered for the supply of Loads directly connected to the transmission facilities or Distribution System of a UDC or MSS, and all Energy provided by a Scheduling Coordinator for the supply of Loads not directly connected to the transmission facilities or Distribution System of a UDC or MSS. Gross Load shall exclude Load with respect to which the Wheeling Access Charge is payable and the portion of the Load of an individual retail customer of a UDC, MSS, or Scheduling Coordinator that is served by a Generating Unit that: (a) is located on the customer's site or provides service to the customers site through over-the-fence arrangements as authorized by Section 218 of the California Public Utilities Code; (b) is a qualifying small power production facility or qualifying cogeneration facility, as those terms are defined in the FERC's regulations implementing Section 201 of the Public Utility Regulatory Policies Act of 1978; (c) was serving the customer's

High Voltage Transmission Standby Serve	Service provided by a Participating TO which allows a Standby Service Customer to utilize the Participating TO's High Voltage Transmission Facilities as a backup to ensure that Energy may be reliably delivered to the Standby Service Customer in the event of an outage of a Generating Unit located on or near the customer's premise.
High Voltage Wheeling Access Charge	The Wheeling Access Charge associated with the recovery of a Participating TO's High Voltage Transmission Revenue Requirements in accordance with Section 7.1.
Hour-Ahead	Relating to an Hour-Ahead Market or an Hour-Ahead Schedule.
Hour-Ahead Market	The forward market for Energy and Ancillary Services to be supplied during a particular Settlement Period that is conducted by the ISO which opens after the ISO's acceptance of the Final Day-Ahead Schedule for the Trading Day in which the Settlement Period falls and closes with the ISO's publication of Final Hour-Ahead Schedules.
Hour-Ahead Schedule	A Schedule prepared by a Scheduling Coordinator or the ISO before the beginning of a Settlement Period indicating the changes to the levels of Generation and Demand scheduled for that Settlement Period from that shown in the Final Day-Ahead Schedule.
Hourly Capacity Reservation Costs	Hourly Capacity Reservation Costs has the meaning set forth in Section 5.12.8.1.4.
Hourly Curtailable Demand Costs	Hourly Curtailable Demand Costs has the meaning set forth in Section 5.12.8.1.3.

Hourly Ex Post Price	The Energy-weighted average of the Dispatch Interval Location Marginal Prices for a given Location during each Settlement Period. This price is used for certain Exceptional Dispatches, in the Regulation Energy Payment Adjustment and in RMR settlements.
Hourly Generating Unit Commitment Costs	Hourly Generating Unit Commitment Costs has the meaning set forth in Section 5.12.8.1.1.
Hourly Market Net Revenue	Hourly Market Net Revenue has the meaning set forth in Section 5.12.7.1.1.4.
Hourly Minimum Load Cost Deficiency	Hourly Minimum Load Cost Deficiency has the meaning set forth in Section 5.12.7.1.1.3.
Hourly Pre-Dispatch	The process in which the ISO Dispatches Energy Bids before the start of the next Settlement Period for that Settlement Period.
Hourly System Resource Costs	Hourly System Resource Costs has the meaning set forth in Section 5.12.8.1.2.
Hydro Spill Generation	Hydro-electric Generation in existence prior to the ISO Operations Date that: i) has no storage capacity and that, if backed down, would spill; ii) has exceeded its storage capacity and is spilling even though the generators are at full output, or iii) has inadequate storage capacity to prevent loss of hydro-electric Energy either immediately or during the forecast period, if hydro-electric Generation is reduced; iv) has increased regulated water output to avoid an impending spill.
Identification Code	An identification number assigned to each Scheduling Coordinator by the ISO.

Imbalance Energy	Imbalance Energy is Energy from Regulation, Spinning and Non-Spinning Reserve or Energy from other Generating Units, System Units, System Resources, or Dispatchable Loads that are able to respond to the ISO's request for more or less Energy.
Imputed Cost	The imputed cost is the average cost of Generation at a particular output calculated by the ISO from data provided to the ISO.
Inactive Zone	All Zones which the ISO Governing Board has determined do not have a workably competitive Generation market and as set out in Appendix I to the ISO Tariff.

Incremental Change	The change in dollar value of a specific charge type from the Preliminary Settlement Statement to the Final Settlement Statement including any new charge types or Trading Day charges appearing for the first time on the Final Settlement Statement.
Instructed Imbalance Energy	The real time change in Generation output or Demand (from dispatchable Generating Units, System Units, System Resources or Dispatchable Loads) which is instructed by the ISO to ensure that reliability of the ISO Control Area is maintained in accordance with Applicable Reliability Criteria. Sources of Imbalance Energy include Spinning and Non-Spinning Reserves, and Energy from other dispatchable Generating Units, System Units, System Resources or Dispatchable Loads that are able to respond to the ISO's request for more or less Energy.
Inter-Scheduling Coordinator Ancillary Service Trades	Ancillary Service transactions between Scheduling Coordinators.
Inter-Scheduling Energy Coordinator Trades	Energy transactions between Scheduling Coordinators.

Inter-Zonal Scheduling Charge	The component of the Grid Management Charge that provides for the recovery of the ISO's costs of operating the Congestion Management process.
Interconnection	Transmission facilities, other than additions or replacements to existing facilities that: i) connect one system to another system where the facilities emerge from one and only one substation of the two systems and are functionally separate from the ISO Controlled Grid facilities such that the facilities are, or can be, operated and planned as a single facility; or ii) are identified as radial transmission lines pursuant to contract; or iii) produce Generation at a single point on the ISO Controlled Grid; provided that such interconnection does not include facilities that, if not owned by the Participating TO, would result in a reduction in the ISO's Operational Control of the Participating TO's portion of the ISO Controlled Grid.

Interconnecting PTO	For purposes of Section 5.7, the Participating TO that will supply the connection to the New Facility.
Interconnection Agreement	A contract between a party requesting interconnection and the Participating TO that owns the transmission facility with which the requesting party wishes to interconnect.
Interconnection Application	An application that requests interconnection of a New Facility to the ISO Controlled Grid and that meets the information requirements as specified by the ISO and posted on the ISO Home Page.
Interest	Interest shall be calculated in accordance with the methodology specified for interest on refunds in the regulations of FERC at 18 C.F.R. §35.19(a)(2)(iii) (1996). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt.
Interruptible Imports	Energy sold by a Generator or resource located outside the ISO Controlled Grid which by contract can be interrupted or reduced at the discretion of the seller.
IOU	An investor owned electric utility.
ISO (Independent System Operator)	The California Independent System Operator Corporation, a state chartered, nonprofit corporation that controls the transmission facilities of all Participating TOs and dispatches certain Generating Units and Loads.
ISO Account	The ISO Clearing Account, the ISO Reserve Account or such other trust accounts as the ISO deems necessary or convenient for the purpose of efficiently implementing the funds transfer system under the ISO Tariff.

ISO ADR Procedures	The procedures for resolution of disputes or differences set out in Section 13 of the ISO Tariff, as amended from time to time.
ISO Adjusted Demand Forecast	The Demand Forecast set forth in 5.12.6.1.1.1.
ISO Audit Committee	A Committee of the ISO Governing Board appointed pursuant to Article IV, Section 5 of the ISO bylaws to (1) review the ISO's annual independent audit (2) report to the ISO Governing Board on such audit, and (3) to monitor compliance with the ISO Code of Conduct.
ISO Authorized Inspector	A person authorized by the ISO to certify, test, inspect and audit meters and metering facilities in accordance with the procedures established by the ISO pursuant to the ISO Protocols on metering.
ISO Bank	The bank appointed by the ISO from time to time for the purposes of operating the Settlement process.
ISO Clearing Account	The account in the name of the ISO with the ISO Bank to which payments are required to be transferred for allocation to ISO Creditors in accordance with their respective entitlements.
ISO Code of Conduct	For employees, the code of conduct for officers, employees and substantially full-time consultants and contractors of the ISO as set out in exhibit A to the ISO bylaws; for Governors, the code of conduct for governors of the ISO as set out in exhibit B to the ISO bylaws.
ISO Commitment Period	ISO Commitment Period has the meaning set forth in Section 5.12.7.1.1.2.3.

ISO Control Area Balancing Function	The real time Dispatch of Generation (and Curtailable Demand), directed by the ISO, to balance with actual Demand during the current operating hour to meet operating reliability criteria.
ISO Control Center	The Control Center established, pursuant to Section 2.3.1.1 of the ISO Tariff.

ISO Grid Operations Committee	A committee appointed by the ISO Governing Board pursuant to Article IV, Section 4 of the ISO bylaws to advise on additions and revisions to its rules and protocols, tariffs, reliability and operating standards and other technical matters.
ISP (Internet Service Provider)	An independent network service organization engaged by the ISO to establish, implement and operate Wenet.
Load	An end-use device of an End-Use Customer that consumes power. Load should not be confused with Demand, which is the measure of power that a Load receives or requires.
Load Aggregation Point	A set of network nodes that satisfy ISO-specified criteria and may be used for scheduling and settlement of Load.
Load Distribution Factor (LDF)	A number that states the relative amount of Load at each node within a Load Aggregation Point. The sum of all LDFs for a single Load Aggregation Point equals one (1.0).
Load Serving Entity (LSE)	Any Market Participant (or the duly designated agent of such an entity, including, e.g., a Scheduling Coordinator), including a load aggregator or power marketer, (i) serving End Users within the ISO Control Area and (ii) that has been granted the authority or has an obligation pursuant to California State or local law, regulation or franchise to sell electric energy to End Users located within the ISO Control Area.
Load Shedding	The systematic reduction of system Demand by temporarily decreasing the supply of Energy to Loads in response to transmission system or area capacity shortages, system instability, or voltage control considerations.

Load Zone	A standard set of network nodes located within the ISO Control Area that has been designated by the ISO to simplify Load scheduling and Settlement.
Local Furnishing Bond	Tax-exempt bonds utilized to finance facilities for the local furnishing of electric energy, as described in section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f).
Local Furnishing Participating TO	Any Tax-Exempt Participating TO that owns facilities financed by Local Furnishing Bonds.
Local Publicly Owned Electric Utilities	A municipality or municipal corporation operating as a public utility furnishing electric service, a municipal utility district furnishing electric service, a public utility district furnishing electric services, an irrigation district furnishing electric services, a state agency or subdivision furnishing electric services, a rural cooperative furnishing electric services, or a joint powers authority that includes one or more of these agencies and that owns Generation or transmission facilities, or furnishes electric services over its own or its members' electric Distribution System.

Local Regulatory Authority	The state or local governmental authority responsible for the regulation or oversight of a utility.
Local Reliability Criteria	Reliability criteria established at the ISO Operations Date, unique to the transmission systems of each of the Participating TOs.
Location	A network node, Load Aggregation Point or Trading Hub.
Location Code	The code assigned by the ISO to Generation input points, and Demand Take-Out Points from the ISO Controlled Grid, and transaction points from trades between Scheduling Coordinators. This will be the information used by the ISO Controlled Grid, and transaction points for trades between Scheduling Coordinators. This will be the information used by the ISO to determine the location of the input, output, and trade points of Energy Schedules. Each Generation input and Demand Take-Out Point will have a designated Location Code identification for use in submitting Energy and Ancillary Service bids and Schedules.

Locational Marginal Price	The marginal price of Energy at a particular Location in a given market.
Loop Flow	Energy flow over a transmission system caused by parties external to that system.
Low Voltage Access Charge	The Access Charge applicable under Section 7.1 to recover the Low Voltage Transmission Revenue Requirement of a Participating TO.

Low Voltage Transmission Facility	A transmission facility owned by a Participating TO or to which a Participating TO has an Entitlement that is represented by a Converted Right, which is not a High Voltage Transmission Facility.

Low Voltage Transmission Revenue Requirement	The portion of a Participating TO's TRR associated with and allocable to the Participating TO's Low Voltage Transmission Facilities and Converted Rights associated with Low Voltage Transmission Facilities.
Low Voltage Wheeling Access Charge	The Wheeling Access Charge associated with the recovery of a Participating TO's Low Voltage Transmission Revenue Requirement in accordance with Section 7.1.
Maintenance Outage	A period of time during which an Operator (i) takes its transmission facilities out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work or for work on de-energized and live transmission facilities (e.g., relay maintenance or insulator washing) and associated equipment; or (ii) takes its Generating Unit or System Unit out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work.
Marginal Generators	Those Generating Units which, in an hour, are the sources of the last increments of Generation in the Preferred Schedule, excluding: (i) Must-Run Generation, (ii) Must-Take Generation, (iii) units scheduled to ramp at their maximum ramp rate throughout the hour, or (iv) units operating at minimum operating levels (when less costly Generation must be backed down).

Master File	A file containing information regarding Generating Units, Loads and other resources.
Meter Data	Energy usage data collected by a metering device or as may be otherwise derived by the use of Approved Load Profiles.
Meter Distribution Factors	Load Distribution Factors that apply to Settlement Quality Meter Data of a Load aggregation for Imbalance Energy Settlement.
Meter Points	Locations on the ISO Controlled Grid at which the ISO requires the collection of Meter Data by a metering device.
Metered Quantities	For each Direct Access End-User, the actual metered amount of MWh and MW; for each Participating Generator the actual metered amounts of MWh, MW, MVAr and MVArh.
Minimum Load Cost	Minimum Load Cost has the meaning set forth in Section 5.12.7.1.1.3.1.
Monthly Peak Load	The maximum hourly Demand on a Participating TO's transmission system for a calendar month, multiplied by the Operating Reserve Multiplier.
MSS (Metered Subsystem)	A geographically contiguous system of a New Participating TO, located within a single Zone which has been operating for a number of years prior to the ISO Operations Date subsumed within the ISO Control Area and encompassed by ISO certified revenue quality meters at each interface point with the ISO Controlled Grid and ISO certified revenue quality meters on all Generating Units internal to the system, which is operated in accordance with an agreement described in Section 3.3.1.
MSS Operator	An entity that owns an MSS and has executed an agreement described in Section 3.3.1.

Municipal Tax Exempt Debt	An obligation the interest on which is excluded from gross income for federal tax purposes pursuant to Section 103(a) of the Internal Revenue Code of 1986 or the corresponding provisions of prior law without regard to the identity of the holder thereof. Municipal Tax Exempt Debt does not include Local Furnishing Bonds.
Municipal Tax Exempt TO	A Transmission Owner that has issued Municipal Tax Exempt Debt with respect to any transmission facilities, or rights associated therewith, that it would be required to place under the ISO's Operational Control pursuant to the Transmission Control Agreement if it were a Participating TO.
Native Load	Load required to be served by a utility within its Service Area pursuant to applicable law, franchise, or statute.
NERC	The North American Electric Reliability Council or its successor.
Net Negative Demand Deviations	Net Negative Demand Deviations has the meaning set forth in Section 5.12.8.2.1.1.
Net Negative Uninstructed Deviation	The real time change in Generation or Demand associated with underscheduled Load (i.e., Load that appears unscheduled in real time) and overscheduled Generation (i.e., Generation that is scheduled in forward markets and does not appear in real time). Deviations are netted for each Dispatch Interval, apply to a Scheduling Coordinator's entire portfolio, and include Load, Generation, Imports and Exports.

New Facility	A planned or Existing Generating Unit that requests, pursuant to Section 5.7 of the ISO Tariff, to interconnect or modify its interconnection to the ISO Controlled Grid.
New Facility License	A license issued by a federal, state or Local Regulatory Authority that enables an entity to build and operate a Generating Unit.
New Facility Operator	The owner of a planned New Facility, or its designee.
New High Voltage Facility	A High Voltage Transmission Facility of a Participating TO that enters service after the beginning of the transition period described in Section 4 of Schedule 3 of Appendix F, or a capital addition made after the beginning of the transition period described in Section 4.1 of Schedule 3 of Appendix F to an Existing High Voltage Transmission Facility.
New Participating TO	A Participating TO that is not an Original Participating TO.
Nomogram	A set of operating or scheduling rules which are used to ensure that simultaneous operating limits are respected, in order to meet NERC and WSCC operating criteria.

Non-ISO Transmission Facilities	Transmission facilities, either inside or outside the State of California, over which the ISO does not exert Operational Control.
Non-Participating Generator	A Generator that is not a Participating Generator.
Non-Participating TO	A TO that is not a party to the TCA or for the purposes of Sections 2.4.3 and 2.4.4 of the ISO Tariff the holder of transmission service rights under an Existing Contract that is not a Participating TO.
Non-Spinning Reserve	The portion of off-line generating capacity that is capable of being synchronized and ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted) for at least two hours.
NRC	The Nuclear Regulatory Commission or its successor.
Operating Procedures	Procedures governing the operation of the ISO Controlled Grid as the ISO may from time to time develop, and/or procedures that Participating TOs currently employ which the ISO adopts for use.

<u>Order No. 889</u>	The final rule issued by FERC entitled "Open Access Same-Time Information System (formerly Real Time Information Networks) and Standards of Conduct," 61 Fed. Reg. 21,737 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles [1991-1996] ¶ 31,035 (1996), Order on Rehearing, Order No. 889-A, 78 FERC ¶ 61,221 (1997), as it may be amended from time to time.
<u>Original Participating TO</u>	A Participating TO that was a Participating TO as of January 1, 2000.
<u>Outage</u>	Disconnection or separation, planned or forced, of one or more elements of an electric system.
<u>Overgeneration</u>	A condition that occurs when total Generation exceeds total Demand in the ISO Control Area.
<u>Participating Buyer</u>	A Direct Access End-User or a wholesale buyer of Energy or Ancillary Services through Scheduling Coordinators.
<u>Participating Load</u>	An entity that has undertaken in writing to comply with all applicable provisions of the ISO Tariff in regards to Load, as they may be amended from time to time.
<u>Participating Seller</u> or <u>Participating Generator</u>	A Generator or other seller of Energy or Ancillary Services through a Scheduling Coordinator over the ISO Controlled Grid from a generating unit with a rated capacity of 1 MW or greater, or from a generating unit providing Ancillary Services and/or submitting Supplemental Energy Bids through an aggregation

Participating TO	A party to the TCA whose application under Section 2.2 of the TCA has been accepted and who has placed its transmission assets and Entitlements under the ISO's Operational Control in accordance with the TCA. A Participating TO may be an Original Participating TO or a New Participating TO.
Payment Date	The date by which invoiced amounts are to be paid under the terms of the ISO Tariff.
PBR (Performance-Based Ratemaking)	Regulated rates based in whole or in part on the achievement of specified performance objectives.

Physical Scheduling Plant A group of two or more related Generating Units, each of which is individually capable of producing Energy, but which either by physical necessity or operational design must be operated as if they were a single Generating Unit and any Generating Unit or Units containing related multiple generating components which meet one or more of the following criteria: i) multiple generating components are related by a common flow of fuel which cannot be interrupted without a substantial loss of efficiency of the combined output of all components; ii) the Energy production from one component necessarily causes Energy production from other components; iii) the operational arrangement of related multiple generating components determines the overall physical efficiency of the combined output of all components; iv) the level of coordination required to schedule individual generating components would cause the ISO to incur scheduling costs far in excess of the benefits of having scheduled such individual components separately; or

	v) metered output is available only for the combined output of related multiple generating components and separate generating component metering is either impractical or economically inefficient.
<u>Planning Procedures</u>	Procedures governing the planning, expansion and reliable interconnection to the ISO Controlled Grid that the ISO may, from time to time, develop.
<u>Power Flow Model</u>	The network model used by the ISO's network applications (e.g. SCUC, SCED) to model the voltages, power injections and power flows on the ISO Controlled Grid and external systems.
<u>Power Transfer Distribution Factor</u>	The proportion of Energy that flows on any given network branch for an Energy transfer between two specific network nodes.
<u>Preferred Day-Ahead Schedule</u>	A Scheduling Coordinator's Preferred Schedule for the ISO Day-Ahead scheduling process.
<u>Preferred Hour-Ahead Schedule</u>	A Scheduling Coordinator's Preferred Schedule for the ISO Hour-Ahead scheduling process.

Preferred Schedule The initial Schedule produced by a Scheduling Coordinator that represents its preferred mix of Generation to meet its Demand. For each Generator, the Schedule will include the quantity of output and the location of the Generator. For each Load, the Schedule will include the quantity of consumption and the location of the Load. The Schedule may also specify quantities and location of trades between the Scheduling Coordinator and all other Scheduling Coordinators. The Preferred Schedule may be balanced with respect to Generation, Load and trades between Scheduling Coordinators.

Preliminary Settlement Statement The initial statement issued by the ISO of the calculation of the Settlements and allocation of the charges in respect of all Settlement Periods covered by the period to which it relates.

Price Overlap The price range of bids for Supplemental Energy or Energy associated with Ancillary Services bids for any Dispatch Interval that includes decremental and incremental Energy Bids where the price of the decremental Energy Bids exceeds the price of the incremental Energy Bids.

Price Taker A Supply or Demand Schedule without an associated Energy bid.

Project Sponsor A Market Participant or group of Market Participants or a Participating TO that proposes the construction of a transmission addition or upgrade in accordance with Section 3.2 of the ISO Tariff.

Qualifying Hours Qualifying Hours has the meaning set forth in Section 5.12.7.1.1.2.5.

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<u>Request for Expedited Interconnection Procedures</u>	A written request, submitted pursuant to Section 5.7.3.1.1 of the ISO Tariff, by which a New Facility Operator can request expedited processing of its Interconnection Application.

Residual Unit Commitment Process	The process in which the ISO commits Generating Units and reserves service from System Units, System Resources and Curtailable Demands to meet the ISO's projected needs for the next Trading Day.
Responsible Utility	The utility which is a party to the TCA in whose Service Area the Reliability Must-Run Unit is located or whose Service Area is contiguous to the Service Area in which a Reliability Must-Run Unit owned by an entity outside of the ISO Controlled Grid is located.
Revenue Requirement	The revenue level required by a utility to cover expenses made on an investment, while earning a specified rate of return on the investment.
Revenue Review Panel	The panel established by the ISO Governing Board to review the Transmission Revenue Requirement of non-FERC jurisdictional Participating TOs.
RMR Owner	The provider of services under a Reliability Must-Run Contract.
RTG (Regional Transmission Group)	A voluntary organization approved by FERC and composed of transmission owners, transmission users, and other entities, organized to efficiently coordinate the planning, expansion and use of transmission on a regional and inter-regional basis.
SCADA (Supervisory Control and Data Acquisition)	A computer system that allows an electric system operator to remotely monitor and control elements of an electric system.

SC Agreement	An agreement between a Scheduling Coordinator and the ISO whereby the Scheduling Coordinator agrees to comply with all ISO rules, protocols and instructions, as those rules, protocols and instructions may be amended from time to time.
SC Applicant	An applicant for certification by the ISO as a Scheduling Coordinator.

SC Application Form	The form specified by the ISO from time to time in which an SC Applicant must apply to the ISO for certification as a Scheduling Coordinator.
Schedule	A statement of (i) Demand, including quantity, duration and Take-Out Points; or (ii) Generation, including quantity, duration, and location of Generating Unit or Scheduling Point; or (iii) Ancillary Services which will be self provided, (if any) submitted by a Scheduling Coordinator to the ISO or procured by the ISO. "Schedule" includes Preferred Schedules and Final Schedules.
Scheduled Maintenance	Maintenance on Participating Generators, TOs and UDC facilities scheduled more than twenty-four hours in advance.
Scheduling Coordinator	An entity certified by the ISO for the purposes of undertaking the functions specified in Section 2.2.6 of the ISO Tariff.
Scheduling Coordinator Metered Entity or SC Metered Entity	means a Generator, Eligible Customer or End-User that is not an ISO Metered Entity.
Scheduling Distribution Factors	Load Distribution Factors that apply to a Load aggregation for scheduling and Settlement of Day-Ahead and Hour-Ahead Energy.

Scheduling Point	A location at which the ISO Controlled Grid is connected, by a group of transmission paths for which a physical, non-simultaneous transmission capacity rating has been established for Congestion Management, to transmission facilities that are outside the ISO's Operational Control. A Scheduling Point typically is physically located at an "outside" boundary of the ISO Controlled Grid (e.g., at the point of interconnection between a Control Area utility and the ISO Controlled Grid). For most practical purposes, a Scheduling Point can be considered to be a Zone that is outside the ISO's Controlled Grid.
Security Constrained Economic Dispatch (SCED)	The program used by the ISO to Dispatch Energy in real-time as described in Section 31.4.3.2.2.1.
Security Constrained Unit Commitment (SCUC)	The program used by the ISO to commit resources and schedule Energy and Ancillary Services in the Day-Ahead and Hour-Ahead Markets and to perform the Residual Unit Commitment Process. The SCUC incorporates both a unit commitment process and an economic dispatch process.
Security Monitoring	The real time assessment of the ISO Controlled Grid that is conducted to ensure that the system is operating in a secure state, and in compliance with all Applicable Reliability Criteria.

Self-Sufficiency Test Period	For the initial Self-Sufficiency determination for a Participating TO, the Self-Sufficiency Test Period shall be the twelve-month period ending December 31, 1996. The Self-Sufficiency Test Period for a Participating TO undergoing a new Self-Sufficiency determination as a result of the termination or modification of an Existing Contract as referred in Section 7.1.3.2 of the ISO Tariff shall be the twelve-month period ending in the month prior to the month that the Existing Contract was terminated or modified.
Service Area	An area in which, as of December 20, 1995, an IOU or a Local Publicly Owned Electric Utility was obligated to provide electric service to End-Use Customers.
Set Point	Scheduled operating level for each Generating Unit or other resource scheduled to run in the Hour-Ahead Schedule.

Severance Fee	The charge or periodic charge assessed to customers to recover the reasonable uneconomic portion of costs associated with Generation-related assets and obligations, nuclear decommissioning, and capitalized Energy efficiency investment programs approved prior to August 15, 1996 and as defined in the California Assembly Bill No. 1890 approved by the Governor on September 23, 1996.
Spinning Reserve	The portion of unloaded synchronized generating capacity that is immediately responsive to system frequency and that is capable of being loaded in ten minutes, and that is capable of running for at least two hours.
Standard Aggregation	The default aggregation of end-use Loads within the Load Zone.
Standby Rate	Means a rate assessed a Standby Service Customer by the Participating TO, as approved by the Local Regulatory Authority, or FERC, as applicable, for Standby Service which compensates the Participating TO, among other things, for costs of High Voltage Transmission Facilities.
Standby Service	Service provided by a Participating TO which allows a Standby Service Customer, among other things, access to High Voltage Transmission Facilities for the delivery of backup power on an instantaneous basis to ensure that Energy may be reliably delivered to the Standby Service Customer in the event of an outage of a Generating Unit serving the customer's Load.
Standby Service Customer	A retail End-Use Customer of a Participating TO that receives Standby Service and pays a Standby Rate.

Standby Transmission Revenue	The transmission revenues, with respect to cost of both High Voltage Transmission Facilities and Low Voltage Transmission Facilities, collected directly from Standby Service Customers through charges for Standby Service.
State Estimator	An application that estimates the voltages, power flows, transmission losses and other characteristics of the power system at any given time based on measurements.

Supplemental Energy	Energy from Generating Units bound by a Participating Generator Agreement, Loads bound by a Participating Load Agreement, System Units, and System Resources which have uncommitted capacity following finalization of the Hour-Ahead Schedules.
Supply	Generation or import.
Supply Market Participant	Any Generator on behalf of whom Generation and Ancillary Services are scheduled pursuant to the ISO Tariff.

Trading Day	The twenty-four hour period beginning at the start of the hour ending 0100 and ending at the end of the hour ending 2400 daily, except where there is a change to and from daylight savings time.
Trading Hub	A standard aggregation of network nodes defined by the ISO. A Trading Hub may be used as the Source or Sink of an FTR.

Unaccounted for Energy (UFE)	UFE is the difference in Energy, for each UDC Service Area and Settlement Period, between the net Energy delivered into the UDC Service Area, adjusted for UDC Service Area Transmission Losses, and the total metered Demand within the UDC Service Area adjusted for distribution losses using Distribution System loss factors approved by the Local Regulatory Authority. This difference is attributable to meter measurement errors, power flow modeling errors, energy theft, statistical Load profile errors, and distribution loss deviations.
Uncontrollable Force	Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm, flood, earthquake, explosion, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond the reasonable control of the ISO or Market Participant which could not be avoided through the exercise of Good Utility Practice.
Uninstructed Deviation Penalty	The penalty as set forth in Section 11.2.4.1.2 of this ISO Tariff.
Uninstructed Imbalance Energy	The real time change in Generation or Demand other than that instructed by the ISO or which the ISO Tariff provides will be paid at the price for Uninstructed Imbalance Energy.
Unit Commitment	The process of determining which Generating Units will be committed (started) to meet Demand and provide Ancillary Services in the near future (e.g., the next Trading Day).
Universal Node Identifier (UNI)	A unique identification code assigned by each UDC to each End-Use Customer location within that UDC's Distribution System as set forth by the CPUC.

Unrecovered Commitment Costs	Unrecovered Commitment Costs has the meaning set forth in Section 5.12.7.1.1.1.

Voltage Limits	For all substation busses, the normal and post-contingency Voltage Limits (kV). The bandwidth for normal Voltage Limits must fall within the bandwidth of the post-contingency Voltage Limits. Special voltage limitations for abnormal operating conditions such as heavy or light Demand may be specified.
Voltage Support	Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or system emergency conditions.
Waiver Denial Period	The period determined in accordance with Section 5.11.6.
Warning Notice	A Notice issued by the ISO when the operating requirements for the ISO Controlled Grid are not met in the Hour-Ahead Market, or the quantity of Regulation, Spinning Reserve, Non-Spinning Reserve and Supplemental Energy available to the ISO does not satisfy the Applicable Reliability Criteria.
WEnet (Western Energy Network)	An electronic network that facilitates communications and data exchange among the ISO and Market Participants in relation to the status and operation of the ISO Controlled Grid.
Wheeling	Wheeling Out or Wheeling Through.
Wheeling Access Charge	The charge assessed by the ISO that is paid by a Scheduling Coordinator for Wheeling in accordance with Section 7.1. Wheeling Access Charges shall not apply for Wheeling under a bundled non-economy Energy coordination agreement of a Participating TO executed prior to July 9, 1996. The Wheeling Access Charge may consist of a High Voltage Wheeling Access Charge and a Low Voltage Wheeling Access Charge.

Wheeling Out	Except for Existing Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4, the use of the ISO Controlled Grid for the transmission of Energy from a Generating Unit located within the ISO Controlled Grid to serve a Load located outside the transmission and distribution system of a Participating TO.
Wheeling Through	Except for Existing Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4, the use of the ISO Controlled Grid for the transmission of Energy from a resource located outside the ISO Controlled Grid to serve a Load located outside the transmission and distribution system of a Participating TO.
Wholesale Customer	A person wishing to purchase Energy and Ancillary Services at a Bulk Supply Point or a Scheduling Point for resale.
Wholesale Sales	The sale of Energy and Ancillary Services at a Bulk Supply Point or a Scheduling Point for resale.
WSCC (Western System Coordinating Council)	The Western Systems Coordinating Council or its successor.
WSCC Reliability Criteria Agreement	The Western Systems Coordinating Council Reliability Criteria Agreement dated June 18, 1999 among the WSCC and certain of its Member transmission operators, as such may be amended from time to time.

The following table shows the timeline of market events for the ISO, LSEs, and SCs.

Time	ISO	LSE	SC	FTR Owner	PTO	Event
Two Days Ahead						
1800 (6pm)	✓					Publish updated Available Transmission Capacity, Ancillary Services requirements, and 2-day-ahead load forecast.
One Day Ahead						
0600 (6am)	✓					Publish Advisory information (load forecast, Ancillary Services regions and requirements, ATC, LDFs, PTDFs)
0600 (6am)	✓					Update system load forecast and ancillary service requirements
0600 (6am)		✓				Submit Direct Access Customer load forecast
0630 (6:30am)	✓					Publish forecasted Direct Access load by UDC
By 0800 (8am) (By 2 hours before the deadline for submitting Preferred DA Schedules)	✓					Notify Scheduling Coordinators of unit-specific Reliability Must Run requirement
0800 (8am)				✓		FTR holder notify ISO via Secondary Registration System of ownership quantities and Scheduling Coordinator scheduling responsibility.
0830 (8:30 am)					✓	Participating Transmission Owner will notify ISO amounts transmission capacity to reserve for its transmission service customers under Existing Contracts.
By 0800 (8am) (By 2 hours before the deadline for submitting Preferred DA Schedules)			✓			Scheduling Coordinators representing Reliability Must Run resources notify ISO of Payment Option selection associated with unit-specific Reliability Must Run notification.
0900 (9am)	✓					Publish Firm Transmission Rights and Existing Contract rights available for scheduling for the Day-Ahead market.

Time	ISO	LSE	SC	FTR Owner	PTO	Event
1000 (10am)			✓			Submit DA Energy, start-up and minimum load energy and Ancillary Services Schedules and bids. Bids submitted at this time shall be used for both the DA Market as well as the DA Residual Unit Commitment process.
1000 (10am)	✓					Validate all SC Energy schedules including RMR requirements and bids, notify and resolve incorrect schedules and bids if any. Validate all SC Ancillary Service schedules and bids notify and resolve incorrect Ancillary Service schedules and bids if any.
1000 (10am)	✓					Close DA market; simultaneous DA Energy market, DA Unit Commitment, DA Congestion Management, and DA Ancillary Services procurement, subject to Automatic Market Power Mitigation.
1300 (1pm)	✓					Publish final DA Energy and Ancillary Services Schedules, Unit Commitments to meet scheduled load and DA Public Market Information
1330 (1:30pm)	✓					Perform DA Residual Unit Commitment using start-up and minimum load costs data and submitted energy bids from resources, subject to Automatic Market Power Mitigation
Hour-Ahead and Real-Time Market						
Prior to 2300 (11pm) (1 hours prior to OH and every hour thereafter during the TD)			✓			Submit (a set of 24 consecutive hours) HA Energy and Ancillary Service Schedules and bids.
Starting 2300 (11pm) (1 hours prior to OH and every hour thereafter during the TD)			✓			Submit (individual hourly) HA Energy and Ancillary Service Schedules and bids, HA Residual Unit Commitment bids.

Time	ISO	LSE	SC	FTR Owner	PTO	Event
Starting 2300 (11:00pm) (1 hours prior to OH and every hour thereafter during TD)	✓					Close HA market; simultaneous HA Energy market, HA Unit Commitment, HA Congestion Management, and HA Ancillary Services procurement, HA Residual Unit Commitment. Close RT market. Any unused but available energy bid after the HA market has run will be considered in the RT market. Submission of bids into the Hour-Ahead market will be the last opportunity for bids to be submitted to the RT Market.
Starting 2215 (10:15pm) (1hour and 45 minutes prior to the start of OH and every hour thereafter during TD)	✓					Publish final HA Energy and Ancillary Services Schedules and Additional Unit Commitments and DA Public Market Information. Begin RT pre-dispatch process
2330 (30 minutes prior to OH and every hour thereafter during TD)	✓					Complete pre-dispatch subject to Automatic Market Power Mitigation; communicate pre-dispatch instructions through ADS
Every 10 minutes during OH	✓					Perform Real-Time Economic Dispatch; communicate dispatch instruction through ADS; publish 10-minute Ex Post LMPs
End of OH	✓					Publish RT Public Market Information

Legend

M Month of TD

TD Trade Day

DA Day-Ahead

HA Hour-Ahead

OH Operating Hour

RT Real-Time

Schedule 1

Grid Management Charge

Part A – Monthly Calculation of Grid Management Charge (GMC)

The Grid Management Charge consists of three separate service charges: the Control Area Services Charge, the Inter-Zonal Scheduling Charge, and the Market Operations Charge.

1. The rate for the Control Area Services Charge will be calculated by dividing the GMC costs allocated to this service charge by the total Control Area Gross Load and exports, in MWh.

2. The rate for the Inter-Zonal Scheduling Charge will be calculated by dividing the GMC costs allocated to this service charge by the total Scheduling Coordinators' inter-zonal scheduled flow (excluding ETCs) per path in MWh.

3. The rate for the Market Operations Charge will be calculated by dividing the GMC costs allocated to this service charge by the total purchases and sales of Ancillary Services, plus the capacity selected by the ISO in the Residual Unit Commitment Process for which an SC receives a capacity payment, Real-Time Energy, and Imbalance Energy (both instructed and uninstructed) in MWh.

Methodology for Developing the Weighted Average Rate for Wheeling Service

The weighted average rate payable for Wheeling over joint facilities at each Scheduling Point shall be calculated as follows, applying the formula separately to the applicable Wheeling Access Charges:

$$\text{WBAC} = \sum\left(P_n \times \frac{Q_n}{\sum Q_n}\right)$$

Where:

WBAC = Weighted-average Wheeling Access Charge for each ISO Scheduling Point

P_n = The applicable Wheeling Access Charge rate for a TAC Area or Participating TO_n in $/kWh as set forth in Section 7.14 and Section 5 of the TO Tariff.

Q_n = The Available Transmission Capacity (in MW), whether from transmission ownership or contractual entitlements, of each Participating TO_n for each ISO Scheduling Point which has been placed within the ISO Controlled Grid. Available Transmission Capacity shall not include capacity associated with Existing Rights of a Participating TO as defined in Section 2.4.4 of the ISO Tariff.

n = the number of Participating TOs from 1 to n

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ISO TARIFF APPENDIX K

LOCATIONAL MARGINAL PRICING

ISO Tariff Appendix K

LOCATIONAL MARGINAL PRICING

K.1 Overview

K.1.1 Simultaneous Energy and Ancillary Services Optimization

The Locational Marginal Prices (LMPs) are based on the marginal costs produced by solving an Alternating Current (AC) Optimal Power Flow (OPF) problem. In forward Energy and Ancillary Service markets, i.e., the Day-Ahead (Day-Ahead) market and the Hour-Ahead (Hour-Ahead) market, the AC OPF program, is referred to as the Security Constrained Unit Commitment (SCUC) process. The SCUC determines which resources should be committed and the optimal power output for each of the committed resources and the hourly LMPs.

K.1.2 Day-Ahead Energy and Ancillary Service Markets

During the Day-Ahead Market, upon receiving the Preferred Day-Ahead Energy schedules and Ancillary Service bids, the SCUC process determines optimally which participating resources and Capacity Resources should be committed in addition to the resources that are already committed previously or self-committed as indicated by the Energy schedules in order to meet the scheduled load and the Ancillary Service requirements in Day-Ahead. The SCUC process is expected to produce optimal decisions on the commitment status of resources. Based on the results of the SCUC, the SCED produces the optimal Day-Ahead Energy schedules, the LMPs for Energy settlement, the quantities and prices of Ancillary Service procurement.

K.1.3 Day-Ahead Residual Unit Commitment

After the Day-Ahead Market, the Day-Ahead Residual Unit Commitment Process (Day-Ahead RUC) is carried out to commit additional resources or de-commit resources as necessary to meet the Day-Ahead ISO Demand Forecast. The Day-Ahead RUC process follows the same SCUC process except that the input to the Day-Ahead RUC process is the Day-Ahead commitment status. The SCUC is used to produce advisory Day-Ahead RUC schedules only; LMPs are not used for any settlement purpose.

K.1.4 Hour-Ahead Energy and Ancillary Service Markets

During the Hour-Ahead Market, upon receiving the Preferred Hour-Ahead Energy schedules and Ancillary Service bids, the SCUC process determines optimally which resources should be committed in addition to the resources that are already committed previously or self-committed as indicated by the Preferred Hour-Ahead Energy schedules in order to meet the scheduled load and the Ancillary Service requirements in Hour-Ahead. The SCUC process is expected to produce optimal decisions on the commitment status of resources. Based on the results of the SCUC, the SCED produces the optimal Hour-Ahead Energy schedules, the LMPs for Energy settlement, the quantities and prices of Ancillary Service procurement. The Hour-Ahead Market is an incremental market; only the incremental amounts of Energy and capacity above those of the Day-Ahead Market are settled at the respective Hour-Ahead Locational Marginal Prices.

K.1.5 Hour-Ahead Residual Unit Commitment

After the Hour-Ahead Market and before the beginning of the hour, the Hour-Ahead Residual Unit Commitment (Hour-Ahead RUC) is carried out to commit additional resources or de-commit resources as necessary to meet the Hour-Ahead ISO Demand Forecast. The Hour-Ahead RUC Process follows the same SCUC process except that the input to the Hour-Ahead RUC process is the Hour-Ahead commitment status. The SCED is used to produce advisory Hour-Ahead RUC schedules only; LMPs are not used for Settlement.

K.1.6 Real-Time Energy Markets

At the beginning of each Dispatch Interval, the resources are dispatched in real-time by the SCED. The SCED uses the commitment status produced by Hour-Ahead RUC, the Supplemental Energy bids and the Ancillary Service Energy bids, and the updated network configuration provided by the state estimator. The Real-Time Market is an incremental market; only the amounts of Energy different than those of the Final Hour-Ahead Schedules are settled at the respective real-time LMPs. The SCED program is used to optimally Dispatch the power output of each committed resource and determine the real-time LMPs during each Dispatch Interval.

K.2 Locational Marginal Pricing of Energy and Ancillary Services

K.2.1 Definition of Nodes

Each resource is defined as a unique node. Multiple resources connected to the same bus bar electrically are considered difference nodes that are linked by zero impedance branches.

K.2.2 AC Power Flow Equations

The AC power flow equations are a set of equations that determine uniquely the nodal injections of active and reactive power and the voltage magnitudes and phase angles. Given a power system with N nodes, the nodes are numbered as follows for convenience without loss of generality:

- PQ nodes (i.e., load or generator operating at reactive power limit) are numbered from 1 to N_d.
- PV nodes (i.e., generator or load with voltage control) are numbered from N_d+1 to N_d+N_g.
- Slack node (i.e., the reference node) is numbered as the last bus, N.

The set of AC power flow equations generally consists of:

- N_d equations that describe the active power balance at the PQ nodes.
- N_g equations that describe the active power balance at the PV nodes,
- N_d equations that describe the reactive power balance at the PQ nodes.

Mathematically, the equations are described as follows:

$$P_i(\mathbf{x}) - P_i = 0 \qquad \text{for i} = 1, 2, \ldots, \text{N-1} \qquad (1)$$

$$Q_i(\mathbf{x}) - Q_i = 0 \qquad \text{for i} = 1, 2, \ldots, \text{N}_\text{d} \qquad (2)$$

where $\mathbf{x} = [\boldsymbol{\theta}^T\ \mathbf{V}^T]^T$ where $\boldsymbol{\theta} = [\theta_1, \theta_2, ..., \theta_{N-1}]^T$ and $\mathbf{V}=[V_1, V_2, \ldots, V_{Nd}]^T$, representing voltage phase angles and magnitudes, respectively. Eq.(1) represents active power balancing equations at all nodes except the reference node and P_i denotes active power injection at node *i*. Eq.(2) represents reactive power balancing equations at the PQ nodes and Q_i denotes reactive injection at node *i*.

K.2.3 Loss Equations

The active power loss of the system is determined by Eq.(3) and the reactive power loss of the system is determined by Eq.(4).

$$\sum_{i=1}^{N} P_i(\mathbf{x}) - P_{loss} = 0 \qquad (3)$$

$$\sum_{i=1}^{N} Q_i(\mathbf{x}) - Q_{loss} = 0 \tag{4}$$

where P_{loss} denotes the active power loss of the system; and Q_{loss} denotes the reactive power loss of the system.

K.2.4 Nodal Power Injection Constraints

The active power injection constraints at all nodes are described as follows:

$$P_i - P_i^{Max} \leq 0 \qquad \text{for i = 1, 2, ..., N} \tag{5}$$

$$P_i^{Min} - P_i \leq 0 \qquad \text{for i = 1, 2, ..., N} \tag{6}$$

where P_i^{Max} is the upper limit of active power injection at node i; and P_i^{Min} is the lower limit of the active power injection at node i.

The reactive power constraints at PV nodes are described as follows:

$$Q_i(\mathbf{x}) - Q_i^{Max} \leq 0 \qquad \text{for } i = N_d+1, N_d+2, \ldots, N_d+N_g \tag{7}$$

$$Q_i^{Min} - Q_i(\mathbf{x}) \leq 0 \qquad \text{for } i = N_d+1, N_d+2, \ldots, N_d+N_g \tag{8}$$

where Q_i^{Max} is the upper limit of reactive power injection at node i; and Q_i^{Min} is the lower limit of the reactive power injection at node i.

Note P_i are independent control variables and $Q_i(\mathbf{x})$ at PV nodes are functions of voltage variables. Reactive power injections at PQ nodes are constants.

K.2.5 Voltage Constraints

The voltage magnitude constraints on PQ nodes are described as follows:

$$V_i - V_i^{Max} \leq 0 \qquad \text{for } i = 1, 2, \ldots, N_d \tag{9}$$

$$V_i^{Min} - V_i \leq 0 \qquad \text{for } i = 1, 2, \ldots, N_d \tag{10}$$

where V_i^{Max} is the upper limit of voltage magnitude at node i; and V_i^{Min} is the lower limit of the voltage magnitude at node i.

The voltage phase angle constraints on all nodes except the reference node are described as follows:

$$\theta_i - \theta_i^{Max} \le 0 \qquad \text{for i = 1, 2, ..., N-1} \qquad (11)$$

$$\theta_i^{Min} - \theta_i \le 0 \qquad \text{for i = 1, 2, ..., N-1} \qquad (12)$$

where θ_i^{Max} is the upper limit of voltage phase angle at node i; and θ_i^{Min} is the lower limit of the voltage phase angle at node i.

K.2.6 Transmission Constraints

The transmission constraints fall into one of the three categories: (i) directional branch constraint, (ii) directional branch group constraint, and (iii) nomogram constraint. Any transmission constraint can be represented in the following form:

$$F_k(\mathbf{x}) - F_k^{Max} \le 0 \qquad (13)$$

or specifically on interties when Ancillary Services compete for use of the available transmission capacity,

$$F_k(\mathbf{x}) + \sum_{i \in T_k} \left(SP_i + NS_i + RU_i\right) - F_k^{Max} \le 0 \qquad (14)$$

where $F_k(\mathbf{x})$ is the power flow carried by the device that is described by constraints k; and F_k^{Max} is the upper limit of the power flow on constraint k; SP_i , NS_i and RU_i are quantities of Spinning Reserve, Non-Spinning Reserve and Regulation Up from resource i provided across intertie k; T_k denotes the set of resources that compete for the use of intertie k; F_k^{Max} is the upper limit of power flow on constraint k.

K.2.7 AC OPF Formulation for Simultaneous Energy and Reserve Auction

The objective is to minimize Energy and Ancillary Services procurement costs based on submitted Energy and Ancillary Services bids. The Lagrange function is as follows:

$$L = \sum_{i=1}^{N-1} C_i(P_i) + C_N\left[P_N(\mathbf{x})\right] + \qquad \text{(Energy Bids)}$$

$$\sum_{i \in I_{RU}} C_i^{RU}(RU_i) + \qquad \text{(Regulation Up Bids)}$$

$$\sum_{i \in I_{SP}} C_i^{SP}(SP_i) +$$ (Spinning Reserve Bids)

$$\sum_{i \in I_{NS}} C_i^{NS}(NS_i) +$$ (Non-Spinning Reserve Bids)

$$\sum_{i \in I_{RD}} C_i^{RD}(RD_i) +$$ (Regulation Down Bids)

$$\sum_{i=1}^{N-1} \lambda_i \left[P_i(\mathbf{x}) - P_i\right] +$$ (Active Power Balance)

$$\sum_{i=1}^{N_d} \gamma_i \left[Q_i(\mathbf{x}) - Q_i\right] +$$ (Reactive power balance at PQ nodes)

$$\sum_j \lambda_j^{RU} \left(R_j^{RU} - \sum_{i \in I_{RU} \cap Z_j} RU_i \right) +$$ (Regulation Up Requirement)

$$\sum_j \lambda_j^{SP} \left(R_j^{RU} + R_j^{SP} - \sum_{i \in I_{RU} \cap Z_j} RU_i - \sum_{i \in I_{SP} \cap Z_j} SP_i \right) +$$ (Spinning Requirement)

$$\sum_j \lambda_j^{NS} \left(R_j^{RU} + R_j^{SP} + R_j^{NS} - \sum_{i \in I_{RU} \cap Z_j} RU_i - \sum_{i \in I_{SP} \cap Z_j} SP_i - \sum_{i \in I_{NS} \cap Z_j} NS_i \right) +$$ (Non Spinning Requirement)

$$\sum_j \lambda_j^{RD} \left(R_j^{RD} - \sum_{i \in I_{RD} \cap Z_j} RD_i \right) +$$ (Regulation Down Requirement)

$$\sum_{i=1}^{N-1} \pi_i^{Max} (P_i + RU_i + SP_i + NS_i - P_i^{Max}) +$$ (Active Power Maximum Limit)

$$\sum_{i=1}^{N-1} \pi_i^{Min} (P_i^{Min} - P_i + RD_i) +$$ (Active Power Minimum Limit)

$$\sum_{i \in I_{RU}} \alpha_i^{RU} \left(RU_i - RU_i^{Max} \right) +$$ (Regulation Up Bid Amount Limit)

$$\sum_{i \in I_{RU}} \beta_i^{RU}\left(-RU_i\right) +$$ (Positive Regulation Up Bid Limit)

$$\sum_{i \in I_{SP}} \alpha_i^{SP}\left(SP_i - SP_i^{Max}\right) +$$ (Spinning Bid Amount Limit)

$$\sum_{i \in I_{SP}} \beta_i^{SP}\left(-SP_i\right) +$$ (Positive Spinning Bid Amount Limit)

$$\sum_{i \in I_{NS}} \alpha_i^{NS}\left(NS_i - NS_i^{Max}\right) +$$ (Non Spinning Bid Amount Limit)

$$\sum_{i \in I_{NS}} \beta_i^{NS}\left(-NS_i\right) +$$ (Positive Non Spinning Bid Amount Limit)

$$\sum_{i \in I_{RD}} \alpha_i^{RD}\left(RD_i - RD_i^{Max}\right) +$$ (Regulation Down Bid Amount Limit)

$$\sum_{i \in I_{RD}} \beta_i^{RD}\left(-RD_i\right) +$$ (Positive Regulation Down Bid Amount Limit)

$$\sum_{i=1}^{N-1} \alpha_i^{OP}(RU_i + SP_i + NS_i - 10RR_i) +$$ (assuming a ten minute Ramp Limit)

$$\sum_k \mu_k \left[F_k(\mathbf{x}) + \sum_{i \in T_k}\left(SP_i + NS_i + RU_i\right) - F_k^{Max} \right]$$ (Network Constraint)

where the symbols are defined as follows:

$C_i(P_i)$	The Energy bid or cost function of resource (i.e.node) i
$C_N(P_N(\mathbf{x}))$	The Energy bid or cost function of reference node N
$C_i^{RU}(RU_i)$	The Regulation Up bid function of resource i
$C_i^{SP}(SP_i)$	The Spinning Reserve bid function of resource i
$C_i^{NS}(NS_i)$	The Non-Spinning Reserve bid function of resource i

$X_\iota^{P\Delta}(P\Delta_\iota)$	The Regulation Down bid function of resource i
PY_ι	The quantity of Regulation Up capacity provided by resource i
$\Sigma\Pi_\iota$	The quantity of Spinning Reserve capacity provided by resource i
$N\Sigma_\iota$	The quantity of Non-Spinning Reserve capacity provided by resource i
$P\Delta_\iota$	The quantity of Regulation Down capacity provided by resource I
λ_ι	The LMP of active power or Energy at node i
γ_ι	The LMP of reactive power at node i
λ_φ^{PY}	The ASMP of Regulation Up in Ancillary Services Region j
P_φ^{PY}	The net requirement of Regulation Up in Ancillary Services Region j
I_{PY}	The set of resources providing Regulation Up
Z_φ	The set of resources in region j
$\lambda_\varphi^{\Sigma\Pi}$	The marginal price of Spinning Reserve in Ancillary Services Region j
$P_\varphi^{\Sigma\Pi}$	The net requirement of Spinning Reserve in Ancillary Services Region j
$I_{\Sigma\Pi}$	The set of resources providing Spinning Reserve
$\lambda_\varphi^{N\Sigma}$	The AMSP of Non-Spinning Reserve in Ancillary Services Region j
$P_\varphi^{N\Sigma}$	The net requirement of Non-Spinning Reserve in Ancillary Services Region j
$I_{N\Sigma}$	The set of resources providing Non-Spinning Reserve
$\lambda_\varphi^{P\Delta}$	The ASMP of Regulation Down in Ancillary Services Region j
$P_\varphi^{P\Delta}$	The net requirement of Regulation Down in Ancillary Services Region j
$I_{P\Delta}$	The set of resources providing Regulation Down
$\pi_\iota^{M\alpha\xi}$	Marginal cost of upper limit of active power at node i
$\pi_\iota^{M\iota\nu}$	Marginal cost of lower limit of active power at node i
α_ι^{PY}	Marginal cost of upper limit of Regulation Up bid at node i
β_ι^{PY}	Marginal cost of lower limit of Regulation Up bid at node i
$PY_\iota^{M\alpha\xi}$	Upper limit of Regulation Up bid at node i
$\alpha_\iota^{\Sigma\Pi}$	Marginal cost of upper limit of Spinning Reserve bid at node i
$\beta_\iota^{\Sigma\Pi}$	Marginal cost of lower limit of Spinning Reserve bid at node i
$\Sigma\Pi_\iota^{M\alpha\xi}$	Upper limit of Spinning Reserve bid at node i
$\alpha_\iota^{N\Sigma}$	Marginal cost of upper limit of Non-Spinning Reserve bid at node i
$\beta_\iota^{N\Sigma}$	Marginal cost of lower limit of Non-Spinning Reserve bid at node i
$N\Sigma_\iota^{M\alpha\xi}$	Upper limit of Spinning Reserve bid at node i
$\alpha_\iota^{P\Delta}$	Marginal cost of upper limit of Regulation Down bid at node i

$\beta_i^{P\Delta}$	Marginal cost of lower limit of Regulation Down bid at node i
$P\Delta_i^{M\alpha\xi}$	Upper limit of Regulation Down bid at node i
$\alpha_i^{O\Pi}$	Marginal cost of 10 minute ramp limit at node i
μ_K	Marginal (shadow) cost of transmission constraint k

K.2.8 Definition of LMP for Energy

The LMP for settlement of Energy at node *i* is determined to be the marginal cost of supplying an additional MW of active power at node *i* as follows:

$$\frac{\partial L}{\partial [P_i(\mathbf{x}) - P_i]} = \lambda_i \tag{15}$$

Each nodal price can be decomposed into three components: (i) marginal cost at the reference bus, (ii) marginal cost of thermal transmission loss, and (iii) marginal cost of transmission system constraints which include but are not limited to transmission line constraints, reactive power supply constraints, voltage constraints, phase angle (e.g., stability) constraints.

$$\lambda_i = \lambda_N - \lambda_N L_i - \sum_k \mu_k S_{ki} \tag{16}$$

where

$\lambda_N = \dfrac{\partial C_N}{\partial P_N}$ = System marginal cost of Energy at the reference node

L_i = The i-th element of the Loss Contribution Factor, $\mathbf{L}$, defined in Section K.2.9, that corresponds to active power injection, i.e., $\dfrac{\partial P_{loss}}{\partial P_i}$.

μ_k = Marginal cost of constraint *k*

S_{ki} = The (*k, i*)-th element of Power Transfer Distribution Factors, $\mathbf{S}$, defined in Section K.2.10, which represents the incremental amount of power flow (MW or MVAR as the case may be) on constraint *k* when a unit of power (MW or MVAR as the case may be) is injected into node *i* and withdrawn at the reference node.

The following mathematical formulas illustrate the theory and procedure for calculating the three components. At the optimal solution, the following Kuhn-Tucker condition must be satisfied:

$$\frac{\partial L}{\partial \mathbf{x}} = \frac{\partial C_N}{\partial P_N}\frac{\partial P_N}{\partial \mathbf{x}} + \sum_{i=1}^{N-1}\lambda_i \frac{\partial P_i}{\partial \mathbf{x}} + \sum_{i=1}^{N_d}\gamma_i \frac{\partial Q_i}{\partial \mathbf{x}} + \sum_k \mu_k \frac{\partial F_k}{\partial \mathbf{x}} = 0 \quad (17)$$

Differentiate (18) on both sides to obtain (19).

$$P_N(\mathbf{x}) = P_{loss}(\mathbf{x}) - \sum_{i=1}^{N-1} P_i(\mathbf{x}) \quad (18)$$

$$\frac{\partial P_N}{\partial \mathbf{x}} = \frac{\partial P_{loss}}{\partial \mathbf{x}} - \sum_{i=1}^{N-1}\frac{\partial P_i}{\partial \mathbf{x}} \quad (19)$$

Substituting (19) into (17) to obtain

$$\sum_{i=1}^{N-1}\left(\lambda_i - \frac{\partial C_N}{\partial P_N}\right)\frac{\partial P_i}{\partial \mathbf{x}} + \sum_{i=1}^{N_d}\gamma_i \frac{\partial Q_i}{\partial \mathbf{x}} = -\frac{\partial C_N}{\partial P_N}\frac{\partial P_{loss}}{\partial \mathbf{x}} - \sum_k \mu_k \frac{\partial F_k}{\partial \mathbf{x}} \quad (20)$$

The above equation can be manipulated and written into vector form as follows:

$$\left[(\lambda_1 - \lambda_N) \quad (\lambda_2 - \lambda_N) \quad \ldots \quad (\lambda_{N-1} - \lambda_N) \quad \gamma_1 \quad \gamma_2 \quad \ldots \quad \gamma_{N_d}\right] = -\lambda_N \mathbf{L} - [\mu_1 \quad \mu_2 \quad \mu_3 \quad \ldots]\cdot \mathbf{S}$$

where γ_i represents the LMP of reactive power at a PQ node *i*, which is not currently used.

K.2.9 Loss Contribution Factor

Loss Contribution Factor relates total system losses to power (active power or reactive power) injection. The Loss Contribution Factors are defined in (21) as follows. The *i*-th element of $\mathbf{L}$ is $\frac{\partial P_{loss}}{\partial P_i}$ or $\frac{\partial P_{loss}}{\partial Q_i}$ as the case may be.

$$\mathbf{L} = \frac{\partial P_{loss}}{\partial \mathbf{x}} \begin{bmatrix} \frac{\partial P_1}{\partial \mathbf{x}} \\ \frac{\partial P_2}{\partial \mathbf{x}} \\ \vdots \\ \frac{\partial P_{N-1}}{\partial \mathbf{x}} \\ \frac{\partial Q_1}{\partial \mathbf{x}} \\ \frac{\partial Q_2}{\partial \mathbf{x}} \\ \vdots \\ \frac{\partial Q_{N_d}}{\partial \mathbf{x}} \end{bmatrix}^{-1} \tag{21}$$

K.2.10 Power Transfer Distribution Factor

Power Transfer Distribution Factors are sensitivities of power flows on transmission constraints (including but not limited to branch thermal constraints, voltage constraints, reactive power constraints and nomogram constraints) with respect to active or reactive power injections. The Power Transfer Distribution Factors are defined as follows in (22). The (k, i)-th element of $\mathbf{S}$ represents the incremental amount of power flow (MW or MVAR as the case may be) on constraint k when a unit of power (MW or MVAR as the case may be) is injected into node i and withdrawn at the reference node.

$$\mathbf{S} = \begin{bmatrix} \frac{\partial F_1}{\partial \mathbf{x}} \\ \frac{\partial F_2}{\partial \mathbf{x}} \\ \frac{\partial F_3}{\partial \mathbf{x}} \\ \vdots \end{bmatrix} \cdot \begin{bmatrix} \frac{\partial P_1}{\partial \mathbf{x}} \\ \frac{\partial P_2}{\partial \mathbf{x}} \\ \vdots \\ \frac{\partial P_{N-1}}{\partial \mathbf{x}} \\ \frac{\partial Q_1}{\partial \mathbf{x}} \\ \frac{\partial Q_2}{\partial \mathbf{x}} \\ \vdots \\ \frac{\partial Q_{N_d}}{\partial \mathbf{x}} \end{bmatrix}^{-1} \tag{22}$$

When DC Power Flow equations are used for modeling the power system, the PTDFs in (22) are simplified as follows:

$$\mathbf{S} = \begin{bmatrix} \frac{\partial F_1}{\partial \boldsymbol{\theta}} \\ \frac{\partial F_2}{\partial \boldsymbol{\theta}} \\ \frac{\partial F_3}{\partial \boldsymbol{\theta}} \\ \vdots \end{bmatrix} \cdot \begin{bmatrix} \frac{\partial P_1}{\partial \boldsymbol{\theta}} \\ \frac{\partial P_2}{\partial \boldsymbol{\theta}} \\ \vdots \\ \frac{\partial P_{N-1}}{\partial \boldsymbol{\theta}} \end{bmatrix}^{-1} \qquad (23)$$

where

F_i = the active power flow carried by constraint *i*, which is represented as a function of phase angles θ.

P_i = the active power injection at node *i*, which is represented as a function of phase angles θ by the DC Power Flow equation:

$$\mathbf{B}\,\theta = \mathbf{P} \qquad (24)$$

B = The bus admittance matrix.

θ = $[\theta_1, \theta_2, ..., \theta_{N-1}]^T$ the vector of phase angles.

P = $[P_1, P_2, ..., P_{N-1}]^T$, the vector of active power nodal injections.

K.2.11 LMPs for Load Aggregation Points

The computation described above is at node level. The LMP for a Load Aggregation Point will be a Load-weighted average of the nodal LMPs of the underlying network nodes. The Load weights are the Load Distribution Factors predetermined by the ISO according to Section 31.

K.2.12 Definition of ASMP for Regulation Up

The ASMP for Regulation Up in Ancillary Service Region *j* is determined to be the marginal cost of supplying an additional MW of Regulation Up in Ancillary Service Region *j* as follows:

$$\frac{\partial L}{\partial\left(R_j^{RU} - \sum_{i \in I_{RU} \cap Z_j} RU_i\right)} = \lambda_j^{RU} + \lambda_j^{SP} + \lambda_j^{NS} \qquad (25)$$

A supplier of Regulation Up that produces less Energy in the corresponding market (i.e., Day-Ahead or Hour-Ahead) than it would have been economic for it to produce because of its selection to provide Regulation Up is paid its opportunity cost through the ASMP for Regulation Up defined above.

K.2.12.1 Opportunity Cost for Provision of Regulation Up

The foregone profit associated with the provision of Regulation Up is equal to the product of (1) the difference between (a) the Energy that a Generator could have sold at the specific LMP and (b) the Energy sold as a result of reducing the Generator's output to provide Regulation Up at the direction of the ISO; and (2) the LMP existing at the time the Generator was selected to provide the Regulation Up, less the Generator's Energy bid for the Energy that was not scheduled due to the provision of Regulation Up.

K.2.13 Definition of ASMP for Spinning Reserve

The ASMP for Spinning Reserve in Ancillary Service Region *j* is determined to be the marginal cost of supplying an additional MW of Spinning Reserve in Ancillary Service Region *j* as follows:

$$\frac{\partial L}{\partial\left(R_j^{SP} - \sum_{i \in I_{SP} \cap Z_j} SP_i\right)} = \lambda_j^{SP} + \lambda_j^{NS} \qquad (26)$$

A supplier of Spinning Reserve that produces less Energy in the corresponding market (i.e., Day-Ahead or Hour-Ahead) than it would have been economic for it to produce because of its selection to provide Spinning Reserve is paid for its opportunity cost through the ASMP for Spinning Reserve as defined above.

K.2.13.1 Opportunity Cost for Provision of Spinning Reserve

The foregone profit associated with the provision of Spinning Reserve is equal to the product of (1) the difference between (a) the Energy that a Generator could have sold at the specific LMP and (b) the Energy sold as a result of reducing the Generator's output to provide Spinning Reserve at the direction of the ISO; and (2) the LMP existing at the time the Generator was selected to provide the Spinning Reserve, less the Generator's Energy bid for the Energy that was not scheduled due to the provision of Spinning Reserve..

K.2.14 Definition of ASMP for Non-Spinning Reserve

The ASMP for Non-Spinning Reserve in Ancillary Service Region *j* is determined to be the marginal cost of supplying an additional MW of Non-Spinning Reserve in Ancillary Service Region *j* as follows:

$$\frac{\partial L}{\partial\left(R_j^{NS} - \sum_{i \in I_{NS} \cap Z_j} NS_i\right)} = \lambda_j^{NS} \tag{27}$$

A supplier of Non-Spinning Reserve that produces less Energy in the corresponding market (i.e., Day-Ahead or Hour-Ahead) than it would have been economic for it to produce because of its selection to provide Non-Spinning Reserve is paid for its opportunity costs through the ASMP for Non-Spinning Reserve as defined above.

K.2.14.1 Opportunity Costs for Provision of Non-Spinning Reserve

The foregone profit associated with the provision of Non-Spinning Reserve is equal to the product of (1) the difference between (a) the Energy that a Generator could have sold at the specific LMP and (b) the Energy sold as a result of reducing the Generator's output to provide Non-Spinning Reserve at the direction of the ISO; and (2) the LMP existing at the time the Generator was selected to provide the Non-Spinning Reserve, less the Generator's Energy bid for the Energy that was not scheduled due to the provision of Non-Spinning Reserve.

K.2.15 Definition of ASMP for Regulation Down

The ASMP for Regulation Down in Ancillary Service Region *j* is determined to be the marginal cost of supplying an additional MW of Regulation Down in Ancillary Service Region *j* as follows:

$$\frac{\partial L}{\partial\left(R_j^{RD} - \sum_{i \in I_{RD} \cap Z_j} RD_i\right)} = \lambda_j^{RD} \tag{28}$$

A supplier of Regulation Down that produces more Energy in the corresponding market (i.e., Day-Ahead or Hour-Ahead) than it would have been economic for it to produce because of its selection to provide Regulation Down is paid its opportunity costs through the ASMP for Regulation Down as defined above.

K.2.15.1 Opportunity Cost for Provision of Regulation Down

The foregone profit associated with the provision of Regulation Down is equal to the product of (1) the difference between (a) the Energy sold as a result of increasing the Generator's output to provide Regulation Down at the direction of the ISO and; (b) the Energy that a Generator could have sold at the specific LMP; and (2) the Generator's Energy bid at the time the Generator was selected to provide the Regulation Down, less the LMP for the Energy that was scheduled in order to provide Regulation Down.

K.2.16 Definition of Shadow Price for Network Constraints

The shadow price for network constraint *k* is determined to be the marginal cost of relaxing the constraint by one additional unit as follows:

$$\frac{\partial L}{\partial\left[F_k(\mathbf{x})+\sum_{i\in T_k}\left(SP_i+NS_i+RU_i\right)-F_k^{Max}\right]}=\mu_k \qquad (29)$$

K.2.17 Price for Point-To-Point Transmission

The price for using the transmission system to deliver one MW from Source *i* to Sink *j* is defined as follows:

$$\lambda_j-\lambda_i=\lambda_N(L_i-L_j)+\sum_k\mu_k(S_{ki}+S_{kj}) \qquad (30)$$

The first term on the right hand side of (30) represents the cost of losses attributable to the transaction between node *i* and node *j*; and the second term on the right hand side of (30) represents the cost of network constraints.

K.2.18 Price for Network Service Transmission

To avoid double subscripts in notations, any network service transmission can be described, without loss of generality, as the right for sending (p_1, p_2, …, p_s) % of one MW at nodes (1,2, …, s) and receiving (p_{s+1}, p_{s+2}, …, p_{s+r}) % of one MW at nodes (s+1, s+2, …, *s+r*). Using this notation, the price for network service transmission is described as follows:

$$\sum_{j=s+1}^{s+r}\lambda_j p_j - \sum_{i=1}^{s}\lambda_i p_i = \sum_{j=s+1}^{s+r}\left(\lambda_N - \lambda_N L_j - \sum_k \mu_k S_{kj}\right)p_j - \sum_{i=1}^{s}\left(\lambda_N - \lambda_N L_i - \sum_k \mu_k S_{ki}\right)p_i$$
$$= \lambda_N\left(\sum_{i=1}^{s} L_i p_i - \sum_{j=s+1}^{s+r} L_j p_j\right) + \sum_k \mu_k\left(\sum_{i=1}^{s} S_{ki} p_i - \sum_{j=s+1}^{s+r} S_{kj} p_j\right) \tag{31}$$

The first term on the right hand side of (31) represents cost of losses attributable to the transactions associated with the network service; and the second term on the right hand side of (31) represents cost of network constraints. This price is also the value of the Network Service Right with the same network service transmission.

K.2.19 Total Congestion Revenue from Energy Settlement

The total Congestion Revenue collected by the ISO, except for explicit Ancillary Services Congestion charges is as follows:

$$CR = -\sum_{i=1}^{N}\lambda_i P_i = -\sum_{i=1}^{N-1}\lambda_i P_i - \lambda_N P_N = -\sum_{i=1}^{N-1}\left(\lambda_N - \lambda_N L_i - \sum_k \mu_k S_{ki}\right)P_i - \lambda_N P_N$$
$$= \sum_k \mu_k \sum_{i=1}^{N-1}(S_{ki}P_i) - \lambda_N\left[P_N + \sum_{i=1}^{N-1}(1-L_i)P_i\right] = \sum_k \mu_k F_k^{Max} + \lambda_N\left[\sum_{i=1}^{N-1} L_i P_i - P_{loss}\right] \tag{32}$$

The first term on the right hand side of (32) represents revenue associated with network constraints. The second term on the right hand side of (32) represents the difference between actual losses and the marginal cost of losses.

ANCILLARY SERVICES REQUIREMENTS PROTOCOL

Table of Contents

ASRP 2.2 Review of Standards

ASRP 2.2.1 Grid Operations Committee Review

The ISO Grid Operations Committee shall periodically undertake a review of the ISO Controlled Grid operations to determine any revision to the Ancillary Services standards to be used in the ISO Control Area. As a minimum the ISO Technical Advisory Committee shall conduct such reviews to accommodate revisions to WSCC and NERC standards.

ASRP 2.2.2 Contents of Grid Operations Committee Reviews

Periodic reviews may include, but are not limited to:

(a) analysis of the deviation between actual and forecast Demand;

(b) analysis of patterns of unplanned Generating Unit Outages;

(c) analysis of compliance with NERC and WSCC Criteria;

(d) analysis of operation during system disturbances;

(e) analysis of patterns of shortfalls between Final Day-Ahead Schedules and actual Generation and Demand; and

(f) analysis of patterns of unplanned transmission Outages.

ASRP 2.3 Communications

A Participating Generator or provider of Curtailable Demand wishing to offer any Ancillary Service must provide a direct ring down voice communications circuit (or a dedicated telephone line available 24 hours a day every day of the year) between the control room operator for the Generating Unit or Curtailable Demand providing the Ancillary Service and the ISO Control Center. Each Participating Generator must also provide an alternate method of voice communications with the ISO from the control room in addition to the direct communication link required above.

ASRP 3 ANCILLARY SERVICE OBLIGATIONS FOR SCHEDULING COORDINATORS

ASRP 3.1 Ancillary Service Obligations

The ISO shall assign to each Scheduling Coordinator a share of the ISO's total Regulation, Spinning Reserve, and Non-Spinning Reserve requirements. The ISO will calculate the share for which each Scheduling Coordinator is responsible (its "obligation") in accordance with the standards set forth in the ASRP.

ASRP 3.2 Right to Self Provide

Each Scheduling Coordinator may self provide all, or a portion, of its Regulation and Reserve obligation within each Ancillary Services Region or adjust its obligation through Inter-Scheduling Coordinator Ancillary Service Trades.

ASRP 4 REGULATION STANDARDS

ASRP 4.1 Standard for Regulation: Quantity Needed

ASRP 4.1.1 Basis for Standard

The ISO needs sufficient Generating Units immediately responsive to Automatic Generation Control (AGC) in order to allow the ISO Control Area to meet the WSCC and NERC control performance criteria by continuously balancing Generation to meet deviations between actual and scheduled Demand and to maintain interchange schedules.

ASRP 4.1.2 Determination of Regulation Quantity Needed

The quantity of Regulation capacity needed for each Settlement Period of the Day-Ahead Market and the Hour-Ahead Markets shall be determined as a percentage of the IOS-forecasted Demand for that Settlement Period.

ASRP 4.1.3 Percentage Determination

The exact percentage required for each Settlement Period of the Day-Ahead Market and the Hour-Ahead Markets shall be determined by the ISO based upon its need to meet the WSCC and NERC control performance criteria.

ASRP 4.1.4 Publication of Estimated Percentage for Day-Ahead Market

In accordance with the requirements of SP 3.2.1, the ISO will publish on OASIS its estimate of the percentage it will use for determining the quantity of Regulation it requires for each Settlement Period of the Day-Ahead Market for that Trading Day.

ASRP 4.1.5 Publication of Estimated Percentage for Hour-Ahead Market

The ISO will publish on OASIS its estimate of the percentage it will use to determine the quantity of Regulation it requires for each Hour-Ahead Market.

ASRP 4.1.6 Additional Regulation Requirement

Additional Regulation capacity may be procured by the ISO for the real-time operating period if needed to meet the WSCC and NERC control performance criteria.

ASRP 4.2 Standard for Regulation: Performance

ASRP 4.2.1 Operating Characteristics of Generating Unit

A Generating Unit offering Regulation must have the following operating characteristics and technical capabilities:

(a) it must be capable of being controlled and monitored by the ISO Energy Management System (EMS) by means of the installation and use of a standard ISO direct communication and direct control system, a description of which and criteria for any temporary exemption from which, the ISO shall publish on the ISO internet "Home Page;"

(b) it must be capable of achieving at least the ramp rates (increase and decrease in MW/minute) stated in the ISO Master File (which will be updated based on testing or actual performance) for the full amount of Regulation capacity offered;

(c) the Regulation capacity offered must not exceed the maximum ramp rate (MW/minute) of that Unit times a value within a range from a minimum of ten minutes to a maximum of thirty minutes, which value shall be specified by the ISO and published on the ISO's internet "Home Page;"

(d) the Generating Unit to ISO Control Center telemetry must in a manner meeting ISO standards include indications of whether the Generating Unit is on or off AGC at the Generating Unit terminal equipment; and

(e) the Generating Unit must be capable of the full range of movement within the amount of Regulation capability offered without manual Generating Unit operator intervention of any kind.

ASRP 4.2.2 Operational EMS/SCADA Equipment

Each Participating Generator must ensure that the ISO EMS control and related SCADA equipment for its generating facility are operational throughout the time period during which Regulation is required to be provided.

ASRP 4.3 SC's Obligation for Regulation

Each Scheduling Coordinator's Obligation for Regulation for each Settlement Period of the Day-Ahead Market and for each Hour-Ahead Market shall be calculated based upon the ratio of metered Demand (excluding exports) by each Scheduling Coordinator for that Settlement Period to the total metered Demand (excluding exports) for that Settlement Period.

ASRP 4.4 Standard for Regulation: Control

The ACE will be calculated by the ISO EMS. Control signals will be sent from the ISO EMS to raise or lower the output of Generating Units or System Reources providing Regulation when ACE exceeds the allowable ISO Control Area dead band for ACE. Use of dynamic schedules to provide Regulation from System Resources must be certified and approved by the ISO.

ASRP 4.4.1 Dynamic Scheduling of Regulation from External Resources

Scheduling Coordinators are allowed to bid or self-provide their Regulation obligation in whole or in part from resources located outside the ISO Control Area by dynamically scheduling such resources; if it can be demonstrated that the control function will use dedicated communication links (either directly or through EMS computers) for ISO computer control and telemetry to provide this