ISO TARIFF APPENDIX A

Master Definitions Supplement

Access Charge A charge paid by all UDCs and MSS Operators with Gross Load in a PTO Service Territory, 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.

Active Zone The Zones so identified in Appendix I to the ISO Tariff.

Adjustment Bid A bid in the form of a curve defined by (i) the minimum MW output to which a Scheduling Coordinator will permit a resource (Generating Unit or Dispatchable Load) included in its Schedule or, in the case of an inter-Scheduling Coordinator trade, included in its Schedule or the Schedule of another Scheduling Coordinator, to be redispatched by the ISO; (ii) the maximum MW output to which a Scheduling Coordinator will permit the resource included in its Schedule or, in the case of an inter-Scheduling Coordinator trade, included in its Schedule or the Schedule of another Scheduling Coordinator, to be redispatched by the ISO; (iii) up to a specified number of MW values in between; (iv) a preferred MW operating point; and (v) for the ranges between each of the MW values greater than the preferred operating point, corresponding prices (in $/MWh) for

which the Scheduling Coordinator is willing to increase the output of the resource and sell Energy from that resource to the ISO (or, in the case of a Dispatchable Load, decrease the Demand); and (vi) for the ranges between each of the MW values less than the preferred operating point, corresponding prices (in $/MWh) for which the Scheduling Coordinator is willing to decrease the output of the resource and purchase Energy from the ISO at the resource's location (or, in the case of a Dispatchable Load, increase the Demand). This data for an Adjustment Bid must result in a monotonically increasing curve.

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.

Adverse System Impact The negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System An electric system other than the ISO Controlled Grid that may be affected by the proposed interconnection, including the Participating TOs' electric systems that are not part of the ISO Controlled Grid.

Affected System Operator The entity that operates an Affected System.

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, tie-line 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.

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.
Ancillary Services	Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement 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 Provider	A Participating Generator or Participating Load who is eligible to provide an Ancillary Serviced.

Applicable Reliability Criteria	The reliability standards established by NERC, WECC, 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.

Approved Credit Rating

With respect to whether security must be posted for payment of the Grid Management Charge:

(a) A short-term taxable commercial paper debt rating of not less than any one of the following: (i) A1 by Standard and Poor's Corporation; (ii) F1 by Fitch Ratings; or (iii) P1 by Moody's Investors Service. This rating shall be an issuer, or counterpart rating, without the benefit of credit enhancement.

(b) A short-term tax exempt commercial paper debt rating of not less than any one of the following: (i) A1 by Standard and Poor's Corporation; (ii) V1 by Fitch Ratings; or (iii) VMIG1 by Moody's Investors Service. This rating shall be an issuer, or counterparty rating, without the benefit of credit enhancement.

With respect to whether security must be posted for payment of all charges other than the Grid Management Charge:

(c) A short-term tax exempt commercial paper debt rating of not less than any one of the following: (i) A2 by Standard and Poor's Corporation; (ii) F2 by Fitch Ratings; or (iii) P2 by Moody's Investors Service. This rating shall be an issuer, or counterparty rating, without the benefit of credit enhancement.

(d) A short-term tax exempt commercial paper debt rating of not less than any one of the following: (i) A2 by Standard and Poor's Corporation; (ii) V2 by Fitch Ratings; or (iii) VMIG2 by Moody's Investors Service. This rating shall be an issuer, or counterparty rating, without the benefit of credit

enhancement.

(e) A long-term debt rating of not less than any one of the following: (i) A- by Standard and Poor's Corporation; (ii) A- by Fitch Ratings; or (iii) A3 by Moody's Investors Service. This rating shall be an issuer, or counterparty rating, without the benefit of credit enhancement.

With respect to whether security must be posted for payment of all charges:

(f) A federal agency shall be deemed to have an Approved Credit Rating if its financial obligations under the ISO Tariff are backed by the full faith and credit of the United States.

(g) A California state agency shall be deemed to have an Approved Credit Rating if its financial obligations under the ISO Tariff are backed by the full faith and credit of the State of California.

(h) Another credit rating approved by the ISO Governing Board.

Approved Load Profile Local Regulatory Authority approved Load profiles applied to cumulative End-Use Meter Data in order to allocate consumption of Energy to Settlement Periods.

Approved Maintenance Outage A Maintenance Outage which has been approved by the ISO through the ISO Outage Coordination Office.

Automatic Mitigation Procedure (AMP) The market power mitigation procedure described in MMIP Appendix A.

Available Transfer Capacity	For a given transmission path, the capacity rating in MW of the path established consistent with ISO and WECC transmission capacity rating guidelines, less any reserved uses applicable to the path.
Balanced Schedule	A Schedule shall be deemed balanced when Generation, adjusted for Transmission Losses 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.

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	Monday through Friday, excluding federal holidays and the day after Thanksgiving Day.
C.F.R.	Code of Federal Regulations.
Calendar Day	Any day including Saturday, Sunday or a federal holiday.
Circular Schedule	A Schedule or set of Schedules that creates a closed loop of Energy Schedules between the ISO Controlled Grid and one or more other Control Areas that do not have a source and sink in separate Control Areas, which includes Energy scheduled in a counter direction over a Congested Inter-Zonal Interface through two or more Scheduling Points. A closed loop of Energy Schedules that includes a transmission segment on the Pacific DC Intertie shall not be a Circular Schedule because such a Schedule directly changes power flows on the network and can mitigate Congestion between SP15 and NP15. This definition of a Circular Schedule does not apply to the circumstance in which a Scheduling Coordinator submits a Schedule that is an amalgam of different Market Participants' separate but simultaneously submitted Schedules.
Clustering	The process whereby a group of Interconnection Requests is

	studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.
Commercial Operation	The status of a Generating Unit at a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.
Commercial Operation Date	The date on which a Generating Unit at a Generating Facility commences Commercial Operation as agreed to by the applicable Participating TO and the Interconnection Customer pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.
Congestion	A condition that occurs when there is insufficient Available Transfer 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 Management Charge	The component of the Grid Management Charge that provides for the recovery of the ISO's costs of operating the Congestion Management process including, but not limited to, the management and operation of Inter-Zonal Congestion markets, Adjustment Bids, taking Firm Transmission Rights and Existing Contracts into account, and determining the price for mitigating Congestion for flows on Congested paths. The formula for determining the Congestion Management Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Connected Entity	A Participating TO or any party that owns or operates facilities that are electrically interconnected with the ISO Controlled Grid.
Constrained Output Generation	Generating resources with only two viable operating states: (a) off-line or (b) operating at their maximum output level.
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 Minimum Load Costs, Emission 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).

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

Core Reliability Services - Demand Charge A component of the Grid Management Charge that provides for the recovery of the ISO's costs of providing a basic, non-scalable level of reliable operation for the ISO Control Area and meeting regional and national reliability requirements. The formula for determining the Core Reliability Services – Demand Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Core Reliability Services – Energy Export Charge A component of the Grid Management Charge that provides for the recovery of the ISO's costs of providing a basic, non-scalable level of reliable operation for the ISO Control Area and meeting regional and national reliability requirements. The formula for determining the Core Reliability Services – Energy Exports Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

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	Demand from a Participating Load that can be curtailed at the direction of the ISO in the real-time Dispatch of the ISO Controlled Grid. Scheduling Coordinators with Curtailable Demand may offer it to the ISO to meet Non-Spinning Reserve or Replacement Reserve requirements.
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 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.
Default GMM	Pre calculated GMM based on historical Load and interchange levels.

Deliverability Assessment	An evaluation by the Participating TO, ISO or a third party consultant for the Interconnection Customer to determine a list of facilities, the cost of those facilities, and the time required to construct these facilities, that would ensure a Large Generating Facility could provide Energy to the ISO Controlled Grid at peak load, under a variety of severely stressed conditions, such that the aggregate of Generation in the local area can be delivered to the aggregate of Load on the ISO Controlled Grid, consistent with the ISO's reliability criteria and procedures.
Delivery Network Upgrades	Transmission facilities at or beyond the Point of Interconnection, other than Reliability Network Upgrades, identified in the Interconnection Studies to relieve constraints on the ISO Controlled Grid.
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.
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 Forecast	An estimate of Demand over a designated period of time.

Direct Access Demand The Demand of Direct Access End-Users.

Direct Access End-User An Eligible Customer located within the Service Area of a UDC who purchases Energy and Ancillary Services through a Scheduling Coordinator.

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 RTD Software measures deviations in Generation and Demand, and selects Ancillary Service and Supplemental Energy resources to provide balancing Energy in response to such deviations. The Dispatch Interval shall be five (5) minutes. 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 Interval Ex Post Prices	The price of Imbalance Energy determined each Dispatch Interval based on 1) the Imbalance Energy requirements in that Dispatch Interval, and 2) the Energy Bid price of the resource eligible to set the price. The Dispatch Interval Ex Post Price is used to determine other prices used to settle Imbalance Energy.
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 which is the subject of an Adjustment Bid.

Distribution System	The distribution assets of an IOU or Local Publicly Owned Electric Utility.
Distribution Upgrades	The additions, modifications, and upgrades to the Participating TO's electric systems that are not part of the ISO Controlled Grid. Distribution Upgrades do not include Interconnection Facilities.
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.

Eligible Customer	(i) any utility (including Participating TOs, Market Participants and any power marketer), Federal power marketing agency, or any person generating Energy for sale or resale; Energy sold or produced by such entity may be Energy produced in the United States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled transmission service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Participating TO.
Eligible Intermittent Resource	A Generating Unit that is powered solely by 1) wind, 2) solar energy, or 3) hydroelectric potential derived from small conduit water distribution facilities that do not have storage capability.
Emissions Cost Charge	The charge determined in accordance with Section 2.5.23.3.6
Emissions Cost Demand	The level of Demand specified in Section 2.5.23.3.6.3

Emissions Cost Invoice	The invoice submitted to the ISO in accordance with Section 2.5.23.3.6.6.
Emissions Cost Trust Account	The trust account established in accordance with Section 2.5.23.3.6.2.
Emissions Costs	The mitigation fees, excluding capital costs, assessed against a Generating Unit by a state or federal agency, including air quality districts, for exceeding applicable NOx emissions limitations.

EMS (Energy Management System)	A computer control system used by electric utility dispatchers to monitor the real-time performance of the various elements of an electric system and to control Generation and transmission facilities.
Encumbrance	A legal restriction or covenant binding on a Participating TO that affects the operation of any transmission lines or associated facilities and which the ISO needs to take into account in exercising Operational Control over such transmission lines or associated facilities if the Participating TO is not to risk incurring significant liability. Encumbrances shall include Existing Contracts and may include: (1) other legal restrictions or covenants meeting the definition of Encumbrance and arising under other arrangements entered into before the ISO Operations Date, if any; and (2) legal restrictions or covenants meeting the definition of Encumbrance and arising under a contract or other arrangement entered into after the ISO Operations Date.
End-Use Customer or End-User	A consumer of electric power who consumes such power to satisfy a Load directly connected to the ISO Controlled Grid or to a Distribution System and who does not resell the power.
End-Use Meter Data	Meter Data that measures the Energy consumption in respect of End-Users gathered, edited and validated by Scheduling Coordinators and submitted to the ISO in Settlement quality form.
End-Use Meter	A metering device collecting Meter Data with respect to the Energy consumption of an End-User.

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 Generator has agreed to produce the next increment of Energy.
Energy Transmission Services Net Energy Charge	The component of the Grid Management Charge that provides, in conjunction with the Energy Transmission Services Uninstructed Deviations Charge, for the recovery of the ISO's costs of providing reliability on a scalable basis, i.e., a function of the intensity of the use of the transmission system within the Control Area and the occurrence of system outages and disruptions. The formula for determining the Energy Transmission Services Net Energy Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.
Energy Transmission Services Uninstructed Deviations Charge	The component of the Grid Management Charge that provides, in conjunction with the Energy Transmission Services Net Energy Charge, for the recovery of the ISO's costs of providing reliability on a scalable basis, in particular for the costs associated with balancing transmission flows that result from uninstructed deviations. The formula for determining the Energy Transmission Services Uninstructed Deviations Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.
Engineering & Procurement (E&P) Agreement	An agreement that authorizes the Participating TO to begin engineering and procurement of long lead-time items necessary

	for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.
Energy Export	For purposes of calculating the Grid Management Charge, Energy included in an interchange Schedule submitted to the ISO, or dispatched by the ISO, to serve a Load located outside the ISO's Control Area, whether the Energy is produced by a Generator in the ISO Control Area or a resource located outside the ISO's Control Area.
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.
Ex Post GMM	GMM that is calculated utilizing the real-time Power Flow Model in accordance with Section 7.4.2.1.2.
Ex Post Price	The Hourly Ex Post Price, the Dispatch Interval Ex Post Price, the Resource-Specific Settlement Interval Ex Post Price, or the Zonal Settlement Interval Ex Post Price.
Ex Post Transmission Loss	Transmission Loss that is calculated based on Ex Post GMM.

Existing Contracts	The contracts which grant transmission service rights in existence on the ISO Operations Date (including any contracts entered into pursuant to such contracts) as may be amended in accordance with their terms or by agreement between the parties thereto from time to time.
Existing High Voltage Facility	A High Voltage Transmission Facility of a Participating TO that was placed in service on or before the Transition Date defined in Section 4.2 of Schedule 3 of Appendix F.
Existing Rights	Those transmission service rights defined in Section 2.4.4.1.1 of the ISO Tariff.
Facility Owner	An entity owning transmission, Generation, or distribution facilities connected to the ISO Controlled Grid.
Facility Study	An engineering study conducted by a Participating TO to determine required modifications to the Participating TO's transmission system, including the cost and scheduled completion date for such modifications that will be required to provide needed services.
Facility Study Agreement	An agreement between a Participating TO and either a Market Participant, Project Sponsor, or identified principal beneficiaries pursuant to which the Market Participants, Project Sponsor, and identified principal beneficiaries agree to reimburse the Participating TO for the cost of a Facility Study.

FERC	The Federal Energy Regulatory Commission or its successor.
FERC Annual Charges	Those charges assessed against a public utility by the FERC pursuant to 18 C.F.R. § 382.201 and any related statutes or regulations, as they may be amended from time to time.
FERC Annual Charge Recovery Rate	The rate to be paid by Scheduling Coordinators for recovery of FERC Annual Charges assessed against the ISO for transactions on the ISO Controlled Grid.
FERC Annual Charge Trust Account	An account to be established by the ISO for the purpose of maintaining funds collected from Scheduling Coordinators for FERC Annual Charges and disbursing such funds to the FERC.
Final Day-Ahead Schedule	The Day-Ahead Schedule which has been approved as feasible and consistent with all other Schedules by the ISO based upon the ISO's Day-Ahead Congestion Management procedures.

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 Invoice	The invoice due from a RMR Owner to the ISO at termination of the RMR Contract.
Final Schedule	A Schedule developed by the ISO following receipt of a Revised 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.
Forbidden Operating Region	The operating region of a resource wherein the resource cannot operate in a stable manner and must ramp through at maximum ramp capacity.
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.
Forward Scheduling Charge	The component of the Grid Management Charge that provides for the recovery of the ISO's costs, including, but not limited to the costs of providing the ability to Scheduling Coordinators to forward schedule Energy and Ancillary Services and the cost of processing accepted Ancillary Service bids. For purposes of the Forward Scheduling Charge, a schedule is represented by each Final Hour-Ahead Schedule with a value other than 0 MW submitted to the scheduling infrastructure/scheduling

	application system (import, export, Load, Generation, inter-Scheduling Coordinator trade, and Ancillary Services, including self-provided Ancillary Services) submitted to the ISO's scheduling infrastructure. The formula for determining the Forward Scheduling Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.
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 Bidder	An entity that submits a bid in an FTR auction conducted by the ISO in accordance with Section 9.4 of the ISO Tariff.
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 Marginal Loss Rate	A rate calculated by the ISO for each Generation and Scheduling Point location to determine the effect on total system Transmission Losses of injecting an increment of Generation at each such location to serve an equivalent incremental MW of Demand distributed proportionately throughout the ISO Control Area.
Generating Facility	An Interconnection Customer's Generating Unit(s) used for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.
Generating Facility Capacity	The capacity of the Generating Facility and the aggregate capacity of the Generating Facility where it includes multiple energy production devices.
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.

Generator	The seller of Energy or Ancillary Services produced by a Generating Unit.
GMM (Generation Meter Multiplier)	A number which when multiplied by a Generating Unit's Metered Quantity will give the total Demand to be served from that Generating Unit.
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

desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region

Grid Management Charge The ISO monthly charge on all Scheduling Coordinators that provides for the recovery of the ISO's costs listed in Section 8.2 through the eight service charges described in Section 8.3 calculated in accordance with the formula rate set forth in Appendix F, Schedule 1, Part A of this Tariff. The eight charges that comprise the Grid Management Charge consist of: 1) the Core Reliability Services - Demand Charge, 2) the Core Reliability Services – Energy Exports Charge, 3) the Energy Transmission Services Net Energy Charge, 4) the Energy Transmission Services Uninstructed Deviations Charge, 5) the Forward Scheduling Charge, 6) the Congestion Management Charge, 7) the Market Usage Charge, and 8) the Settlements, Metering, and Client Relations Charge.

Grid Operations Charge An ISO charge that recovers Redispatch costs incurred due to Intra-Zonal Congestion in each Zone. These charges will be paid to the ISO by the Scheduling Coordinators, in proportion to their metered Demand within, and metered exports from, the Zone to a neighboring Control Area.

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 End-Use Customer Loads directly connected to the transmission facilities or directly connected to the Distribution System of a UDC or MSS Operator located in a PTO Service Territory. 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 or MSS Operator that is served by a Generating Unit that: (a) is located on the customer's site or provides service to the customers site through 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; and

(c) secures Standby Service from a Participating TO under terms approved by a Local Regulatory Authority or FERC, as applicable, or can be curtailed concurrently with an outage of the Generating Unit serving the Load. Gross Load forecasts consistent with filed TRR will be provided by each Participating TO to the ISO.

High Voltage Access Charge — The Access Charge applicable under Section 7.1 to recover the High Voltage Transmission Revenue Requirements of each Participating TO in a TAC Area.

High Voltage Transmission Facility — A transmission facility that is owned by a Participating TO or to which a Participating TO has an Entitlement that is represented by a Converted Right, that is under the ISO Operational Control, and that operates at a voltage at or above 200 kilovolts, and supporting facilities, and the costs of which are not directly assigned to one or more specific customers.

High Voltage Transmission Revenue Requirement — The portion of a Participating TO's TRR associated with and allocable to the Participating TO's High Voltage Transmission Facilities and Converted Rights associated with High Voltage Transmission Facilities that are under the ISO Operational Control.

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 and other Scheduling Coordinators 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 acceptance of the Final Hour-Ahead Schedule.
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 Ex Post Price	The Energy-weighted average of the Dispatch Interval Ex Post Prices in each Zone during each Settlement Period. The Hourly Ex Post Price will vary between Zones when Congestion is present. This price is used in the Regulation Energy Payment Adjustment and in RMR settlements.
Hourly Pre-Dispatch	The process in which the ISO Dispatches Energy Bids from System Resources before the start of the next Settlement Period for the entire duration of that Settlement Period.
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 Reserves, or Replacement Reserve, or Energy from other Generating Units, System Units, System Resources, or Loads that are able to respond to the ISO's request for more or less Energy.
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.
In-Service Date	The date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Participating TO Interconnection Facilities to obtain back feed power.
Instructed Imbalance Energy	The real-time change in Generation output or Demand (from dispatchable Generating Units, System Units, System Resources or 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, Replacement Reserve, and Energy from other dispatchable Generating Units, System Units, System Resources or 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 Coordinator Energy Trades	Energy transactions between Scheduling Coordinators.
Inter-Zonal Congestion	Congestion across an Inter-Zonal Interface.

Inter-Zonal Interface The (i) group of transmission paths between two adjacent Zones of the ISO Controlled Grid, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has been established or will be established prior to the use of the interface for Congestion Management; (ii) the group of transmission paths between an ISO Zone and an adjacent Scheduling Point, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has been established or will be established prior to the use of the interface for Congestion Management; or (iii) the group of transmission paths between two adjacent Scheduling Points, where the group of paths has an established transfer capability and established transmission rights.

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.

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 Customer	Any entity, including a Participating TO or any of its Affiliates or subsidiaries, that proposes to interconnect its Generating Facility with the ISO Controlled Grid.
Interconnection Customer's Interconnection Facilities	All facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the ISO Controlled Grid. Interconnection Customer's Interconnection Facilities are sole use facilities.
Interconnection Facilities	The Participating TO's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the ISO Controlled Grid. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study	A study conducted by the Participating TO(s), ISO, or a third party consultant for the Interconnection Customer to determine a list of facilities (including the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades), the cost of those facilities, and the time required to interconnect the Generating Facility with the ISO Controlled Grid. The scope of the study is defined in Section 8 of the Standard Large Generator Interconnection Procedures.
Interconnection Facilities Study Agreement	The form of agreement accepted by FERC and posted on the ISO Home Page for conducting the Interconnection Facilities Study.
Interconnection Feasibility Study	A preliminary evaluation conducted by the Participating TO(s), ISO, or a third party consultant for the Interconnection Customer of the system impact and cost of interconnecting the Generating Facility to the ISO Controlled Grid, the scope of which is described in Section 6 of the Standard Large Generator Interconnection Procedures.
Interconnection Feasibility Study Agreement	The form of agreement accepted by FERC and posted on the ISO Home Page for conducting the Interconnection Feasibility Study.

Interconnection Handbook	A handbook, developed by the Participating TO and posted on the Participating TO's web site or otherwise made available by the Participating TO, describing technical and operational requirements for wholesale generators and loads connected to the Participating TO's portion of the ISO Controlled Grid, as such handbook may be modified or superseded from time to time. Participating TO's standards contained in the Interconnection Handbook shall be deemed consistent with Good Utility Practice and Applicable Reliability Criteria. In the event of a conflict between the terms of the LGIP and the terms of the Participating TO's Interconnection Handbook, the terms in the LGIP shall apply.
Interconnection Request	An Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with Section 5.7.1 of the ISO Tariff.
Interconnection Service	The service provided by the Participating TO and ISO associated with interconnecting the Interconnection Customer's Generating Facility to the ISO Controlled Grid and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement, the Participating TO's TO Tariff, and the ISO Tariff.

Interconnection Study	Any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Large Generator Interconnection Procedures.
Interconnection System Impact Study	An engineering study conducted by the Participating TO(s), ISO, or a third party consultant for the Interconnection Customer that evaluates the impact of the proposed interconnection on the safety and reliability of the ISO Controlled Grid and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.
Interconnection System Impact Study Agreement	The form of agreement accepted by FERC and posted on the ISO Home Page for conducting the Interconnection System Impact Study.
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, except as provided in SABP 6.10.5. 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.
Intra-Zonal Congestion	Congestion within a Zone.
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 Committee	The Committee appointed by the ISO ADR Committee pursuant to Article IV, Section 3 of the ISO bylaws to perform functions assigned to the ISO ADR Committee in the ADR process in Section 13 of 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 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 (as that term is defined in the ISO Metering Protocol) 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 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 Controlled Grid	The system of transmission lines and associated facilities of the Participating TOs that have been placed under the ISO's Operational Control.
ISO Creditor	A Scheduling Coordinator, Participating TO, or other Market Participant to which amounts are payable under the terms of the ISO Tariff.
ISO Debtor	A Scheduling Coordinator, Participating TO, or other Market Participant that is required to make a payment to the ISO under the ISO Tariff.
ISO Documents	The ISO Tariff, the ISO Protocols, ISO bylaws, and any agreement entered into between the ISO and a Scheduling Coordinator, a Participating TO or any other Market Participant pursuant to the ISO Tariff.
ISO Governing Board	The Board of Governors established to govern the affairs of the ISO.
ISO Home Page	The ISO internet home page at http://www.caiso.com/ or such other internet address as the ISO shall publish from time to time.
ISO Invoice	The invoices issued by the ISO to the Responsible Utilities or RMR Owners based on the Revised Estimated RMR Invoice and the Revised Adjusted RMR Invoice.

ISO Market Any of the markets administered by the ISO under the ISO Tariff, including, without limitation, Imbalance Energy, Ancillary Services, and FTRs.

ISO Memorandum Account The memorandum account established by each California IOU pursuant to California Public Utilities Commission Order D. 96-08-038 date August 2, 1996 which records all ISO startup and development costs incurred by that California IOU.

ISO Metered Entity a) any one of the following entities that is directly connected to the ISO Controlled Grid:

i. a Generator other than a Generator that sells all of its Energy (excluding any Energy consumed by auxiliary load equipment electrically connected to that Generator at the same point) and Ancillary Services to the UDC in whose Service Area it is located;

ii. an Eligible Customer; or

iii. an End-User other than an End-User that purchases all of its Energy from the UDC in whose Service Area it is located; and

(b) any one of the following entities:

i. a Participating Generator;

ii. a Participating TO in relation to its Tie Point Meters with other TOs or Control Areas;

iii. a Participating Load;

iv. a Participating Intermittent Resource; or

v. a utility that requests that UFE for its Service Area be calculated separately, in relation to its meters at points of connection of its Service Area with the systems of other

	utilities.
ISO Operations Date	The date on which the ISO first assumes Operational Control of the ISO Controlled Grid.
ISO Outage Coordination Office	The office established by the ISO to coordinate Maintenance Outages in accordance with Section 2.3.3 of the ISO Tariff.

ISO Payments Calendar A calendar published by the ISO showing the dates on which Settlement Statements will be published by the ISO and the Payment Dates by which invoices issued under the ISO Tariff must be paid.

ISO Protocols The rules, protocols, procedures and standards attached to the ISO Tariff as Appendix L, promulgated by the ISO (as amended from time to time) to be complied with by the ISO Scheduling Coordinators, Participating TOs and all other Market Participants in relation to the operation of the ISO Controlled Grid and the participation in the markets for Energy and Ancillary Services in accordance with the ISO Tariff.

ISO Register The register of all the transmission lines, associated facilities and other necessary components that are at the relevant time being subject to the ISO's Operational Control.

ISO Reserve Account The account established for the purpose of holding cash deposits which may be used in or towards clearing the ISO Clearing Account.

ISO Security Amount The level of security provided in accordance with Section 2.2.3.2 of the ISO Tariff by an SC Applicant who does not have an Approved Credit Rating. The ISO Security Amount may be separated into two components: (i) the level of security required to secure payment of the Grid Management Charge; and (ii) the level of security required to secure payment of all charges other than the Grid Management Charge.

ISO Tariff The California Independent System Operator Corporation Operating Agreement and Tariff, dated March 31, 1997, as it may be modified from time to time.

ISP (Internet Service Provider)	An independent network service organization engaged by the ISO to establish, implement and operate WEnet.
Large Generating Facility	A Generating Facility having a Generating Facility Capacity of more than 20 MW.
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 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.
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 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.
Loop Flow	Energy flow over a transmission system caused by parties external to that system.
Loss Scale Factor	The ratio of expected Transmission Losses to the total Transmission Losses which would be collected if Full Marginal Loss Rates were utilized.
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, that is under the ISO Operational Control.

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 that are under the ISO Operational Control.
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) limits the capability of or 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.

Market Clearing Price The price in a market at which supply equals Demand. All Demand prepared to pay at least this price has been satisfied and all supply prepared to operate at or below this price has been purchased.

Market Participant An entity, including a Scheduling Coordinator, who participates in the Energy marketplace through the buying, selling, transmission, or distribution of Energy or Ancillary Services into, out of, or through the ISO Controlled Grid.

Market Usage Charge The component of the Grid Management Charge that provides for the recovery of the ISO's costs, including, but not limited to the costs for processing Supplemental Energy and Ancillary Service bids, maintaining the Open Access Same-Time Information System, monitoring market performance, ensuring generator compliance with market protocols, and determining Market Clearing Prices. The formula for determining the Market Usage Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Master File	A file containing information regarding Generating Units, Loads and other resources.
Material Modification	Those modifications that have a material impact on the cost or timing of any Interconnection Request or any other valid interconnection request with a later queue priority date.
Meter Data	Energy usage data collected by a metering device or as may be otherwise derived by the use of Approved Load Profiles.
Meter Points	Locations on the ISO Controlled Grid at which the ISO requires the collection of Meter Data by a metering device.
Metered Control Area Load	For purposes of calculating and billing the Grid Management Charge, Metered Control Area Load is: (a) all metered Demand for Energy of Scheduling Coordinators for the supply of Loads in the ISO's Control Area, plus (b) all Energy for exports by Scheduling Coordinators from the ISO Control Area; less (c) Energy associated with the Load of a retail customer of a Scheduling Coordinator, UDC, or MSS that is served by a Generating Unit that: (i) is located on the same site as the customer's Load or provides service to the customer's Load through arrangements as authorized by Section 218 of the California Public Utilities Code; (ii) is a qualifying small power production facility or qualifying cogeneration facility, as those terms are defined in FERC's regulations implementing Section 201 of the Public Utility Regulatory Policies Act of 1978; and (iii) the customer secures Standby Service from a Participating TO under terms approved by a Local Regulatory Authority or FERC, as applicable, or the customer's Load can be curtailed concurrently with an outage of the Generating Unit.

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 Costs	The costs a Generating Unit incurs operating at minimum load.
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 located within a single Zone which has been operating as an electric utility for a number of years prior to the ISO Operations Date as a municipal utility, water district, irrigation district, State agency or Federal power administration 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 or, if aggregated, each individual resource and Participating Load internal to the system, which is operated in accordance with a MSS Agreement described in Section 23.1.
MSS Operator	An entity that owns an MSS and has executed a MSS Agreement.

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.
Must-Offer Generator	All entities defined in Section 5.11.1 of the ISO Tariff
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 FTR Revenue	The sum of: 1) the revenue received by the New Participating TO from the sale, auction, or other transfer of the FTRs provided to it pursuant to Section 9.4.3 FTR, or any substantively identical successor provision of the ISO Tariff; and 2) for each hour: a) the Usage Charge revenue received by the New Participating To associated with its Section 9.4.3 FTRs; minus b) Usage Charges that are: i) incurred by the Scheduling Coordinator for the New Participating TO under ISO Tariff Section 7.3.1.4, ii) associated with the New Participating TO's Section 9.4.3 FTRs, and iii) incurred by the New Participating TO for its energy transactions but not

incurred as a result of the use of the transmission by a third-party and minus c) the charges paid by the New Participating TO pursuant to Section 7.3.1.7, to the extent such charges are incurred by the Scheduling Coordinator of the New Participating TO on Congested Inter-Zonal Interfaces that are associated with the Section 9.4.3 FTRs provided to the New Participating TO. The component of New FTR Revenue represented by item 2) immediately above shall not be less than zero for any hour.

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 Settlement Interval, apply to a Scheduling Coordinator's entire portfolio, and include Load, Generation, imports and exports.

Network Upgrades	The additions, modifications, and upgrades to the ISO Controlled Grid required at or beyond the Point of Interconnection to accommodate the interconnection of the Large Generating Facility to the ISO Controlled Grid. Network Upgrades shall consist of Delivery Network Upgrades and Reliability Network Upgrades.
New High Voltage Facility	A High Voltage Transmission Facility of a Participating TO that is placed in service after the beginning of the transition period described in Section 4 of Schedule 3 of Appendix F, or a capital addition made and placed in service after the beginning of the transition period described in Section 4.2 of Schedule 3 of Appendix F to an Existing High Voltage 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 WECC operating criteria.

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.

Operating Reserve	The combination of Spinning and Non-Spinning Reserve required to meet WECC and NERC requirements for reliable operation of the ISO Control Area.
Operating Transfer Capability	The maximum capability of a transmission path to transmit real power, expressed in MW, at a given point in time.
Operational Control	The rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct Participating TOs how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting Applicable Reliability Criteria.
Operator	The operator of facilities that comprise the ISO Controlled Grid or a Participating Generator.
OPF (Optimal Power Flow)	A computer optimization program which uses a set of control variables (which may include active power and/or reactive power controls) to determine a steady-state operating condition for the transmission grid for which a set of system operating Constraints (which may include active power and/or reactive power constraints) are satisfied and an objective function (e.g. total cost or shift of schedules) is minimized.
Optional Interconnection Study	A sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.
Optional Interconnection Study Agreement	The form of agreement accepted by FERC and posted on the ISO Home Page for conducting the Optional Interconnection Study.

Order No. 888

The final rule issued by FERC entitled "Promoting Wholesale Competition through Open Access Non- discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles [1991-1996] ¶ 31,036 (1996), Order on Rehearing, Order No. 888-A, 78 FERC ¶ 61,220 (1997), as it may be amended from time to time

Order No. 889	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.
Original Participating TO	A Participating TO that was a Participating TO as of January 1, 2000.
Outage	Disconnection, separation or reduction in capacity, planned or forced, of one or more elements of an electric system.
Overgeneration	A condition that occurs when total Generation exceeds total Demand in the ISO Control Area.

Participating Buyer	A Direct Access End-User or a wholesale buyer of Energy or Ancillary Services through Scheduling Coordinators.
Participating Intermittent Resource	One or more Eligible Intermittent Resources that meets the requirements of the technical standards for Participating Intermittent Resources adopted by the ISO and published on the ISO Home Page.
Participating Load	An entity providing Curtailable Demand, which has undertaken in writing to comply with all applicable provisions of the ISO Tariff, as they may be amended from time to time.
Participating Seller or Participating Generator	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 arrangement approved by the ISO, which has undertaken to be bound by the terms of the ISO Tariff, in the case of a Generator through a Participating Generator Agreement.
Participating TO's Interconnection Facilities	All facilities and equipment owned, controlled, or operated by the Participating TO from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Participating TO's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

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.
Path 15 Upgrade	The upgraded transmission facilities across the Path 15 Inter-Zonal Interface that have been turned over to ISO Operational Control.
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.
PMS (Power Management System)	The ISO computer control system used to monitor the real-time performance of the various elements of the ISO Controlled Grid, control Generation, and perform operational power flow studies.
Point of Change of Ownership	The point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Participating TO's Interconnection Facilities.
Point of Interconnection	The point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the ISO Controlled Grid.
Power Flow Model	The computer software used by the ISO to model the voltages, power injections and power flows on the ISO Controlled Grid and determine the expected Transmission Losses and Generation Meter Multipliers.
Preferred Day-Ahead Schedule	A Scheduling Coordinator's Preferred Schedule for the ISO Day-Ahead scheduling process.
Preferred Hour-Ahead Schedule	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, details of any Adjustment Bids, and the location of the Generator. For each Load, the Schedule will include the quantity of consumption, details of any Adjustment Bids, and the location of the Load. The Schedule will also specify quantities and location of trades between the Scheduling Coordinator and all other Scheduling Coordinators. The Preferred Schedule will be balanced with respect to Generation, Transmission Losses, 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.
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.
Proxy Price	The value determined for each gas-fired Generating Unit owned or controlled by a Must-Offer Generator in accordance with Section 2.5.23.3.4.
PTO Service Territory	The area in which an IOU, a Local Public Owned Electric Utility, or federal power marketing administration that has turned over its transmission facilities and/or Entitlements to ISO Operational Control is obligated to provided electric service to Load. A PTO Service Territory may be comprised of the Service Areas of more than one Local Public Owned Electric Utility, if they are operating under an agreement with the ISO for aggregation of their MSS and their MSS Operator is designated as the Participating TO.

Queue Position	The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the ISO.
Ramping	Changing the loading level of a Generating Unit in a constant manner over a fixed time (e.g., ramping up or ramping down). Such changes may be directed by a computer or manual control.
RAS (Remedial Action Schemes)	Protective systems that typically utilize a combination of conventional protective relays, computer-based processors, and telecommunications to accomplish rapid, automated response to unplanned power system events. Also, details of RAS logic and any special requirements for arming of RAS schemes, or changes in RAS programming, that may be required.
Reactive Power Control	Generation or other equipment needed to maintain acceptable voltage levels on the ISO Controlled Grid and to meet reactive capacity requirements at points of interconnection on the ISO Controlled Grid.
Real Time Market	The competitive generation market controlled and coordinated by the ISO for arranging real-time Imbalance Energy.
Redispatch	The readjustment of scheduled Generation or Demand side management measures, to relieve Congestion or manage Energy imbalances.

Registered Data Those items of technical data and operating characteristics relating to Generation, transmission or distribution facilities which are identified to the owners of such facilities as being information, supplied in accordance with ISO Protocols, to assist the ISO to maintain reliability of the ISO Controlled Grid and to carry out its functions.

Regulation	The service provided either by Generating Units certified by the ISO as equipped and capable of responding to the ISO's direct digital control signals, or by System Resources that have been certified by the ISO as capable of delivering such service to the ISO Control Area, in an upward and downward direction to match, on a real-time basis, Demand and resources, consistent with established NERC and WECC operating criteria. Regulation is used 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. Regulation includes both the increase of output by a Generating Unit or System Resource ("Regulation Up") and the decrease in output by a Generating Unit or System Resource ("Regulation Down"). Regulation Up and Regulation Down are distinct capacity products, with separately stated requirements and Market Clearing Prices in each Settlement Period.
Regulation Energy Payment Adjustment	The additional value of regulating Energy.

Regulatory Must-Run Generation	Hydro Spill Generation and Generation which is required to run by applicable Federal or California laws, regulations, or other governing jurisdictional authority. Such requirements include but are not limited to hydrological flow requirements, environmental requirements, such as minimum fish releases, fish pulse releases and water quality requirements, irrigation and water supply requirements of solid waste Generation, or other Generation contracts specified or designated by the jurisdictional regulatory authority as it existed on December 20, 1995, or as revised by Federal or California law or Local Regulatory Authority.
Regulatory Must-Take Generation	Those Generation resources identified by CPUC, or a Local Regulatory Authority, the operation of which is not subject to competition. These resources will be scheduled by the relevant Scheduling Coordinator directly with the ISO on a must-take basis. Regulatory Must-Take Generation includes qualifying facility Generating Units as defined by federal law, nuclear units and pre-existing power purchase contracts with minimum energy take requirements.
Reliability Criteria	Pre-established criteria that are to be followed in order to maintain desired performance of the ISO Controlled Grid under contingency or steady state conditions.
Reliability Must-Run Charge (RMR Charge)	The sum payable by a Responsible Utility to the ISO pursuant to Section 5.2.7 of the ISO Tariff for the costs, net of all applicable credits, incurred under the RMR Contract.

Reliability Must-Run Contract (RMR Contract)	A Must-Run Service Agreement between the owner of an RMR Unit and the ISO.
Reliability Must-Run Generation (RMR Generation)	Generation that the ISO determines is required to be on line to meet Applicable Reliability Criteria requirements. This includes i) Generation constrained on line to meet NERC and WECC reliability criteria for interconnected systems operation; ii) Generation needed to meet Load demand in constrained areas; and iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area.
Reliability Must-Run Unit (RMR Unit)	A Generating Unit which is the subject of a Reliability Must-Run Contract.
Reliability Network Upgrades	The transmission facilities at or beyond the Point of Interconnection necessary to interconnect a Large Generating Facility safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the interconnection of the Large Generating Facility, including Network Upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of the Large Generating Facility to the ISO Controlled Grid. Reliability Network Upgrades also include, consistent with WECC practice, the facilities necessary to mitigate any adverse impact the Large Generating Facility's interconnection may have on a path's WECC rating.
Reliability Services Costs	The costs associated with services provided by the ISO: 1) that are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff. Reliability Services Costs include costs charged by the ISO to a Participating TO associated with service provided

	under an RMR Contract (Section 5.2.8), local out-of-market dispatch calls (Section 11.2.4.2.1) and Minimum Load Costs associated with units committed under the must-offer obligation for local reliability requirements (Section 5.11.6.1.4)
REMnet	The Wide Area Network through which the ISO acquires Meter Data.

Replacement Reserve Generating capacity that is dedicated to the ISO, capable of starting up if not already operating, being synchronized to the ISO Controlled Grid, and Ramping to a specified operating level within a sixty (60) minute period, the output of which can be continuously maintained for a two hour period. Also, Curtailable Demand that is capable of being curtailed within sixty minutes and that can remain curtailed for two hours.

Resource-Specific Settlement Interval Ex Post Price The Resource-Specific Settlement Interval Ex Post Price will equal the Energy-weighted average of the applicable Dispatch Interval Ex Post Prices for each Settlement Interval taking into account each resource's Instructed Imbalance Energy, except Regulation Energy. The Resource-Specific Settlement Interval Ex Post Price shall apply to those resources that are capable of responding to ISO Dispatch Instructions.

Responsible Utility	The utility which is a party to the TCA in whose PTO Service Territory the Reliability Must-Run Unit is located or whose PTO Service Territory is contiguous to the PTO Service Territory 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.
Revised Adjusted RMR Invoice	The monthly invoice issued by the RMR Owner to the ISO pursuant to the RMR Contract reflecting any appropriate revisions to the Adjusted RMR Invoice based on the ISO's validation and actual data for the billing month.
Revised Estimated RMR Invoice	The monthly invoice issued by the RMR Owner to the ISO pursuant to the RMR Contract reflecting appropriate revisions to the Estimated RMR Invoice based on the ISO's validation of the Estimated RMR Invoice.
Revised Schedule	A Schedule submitted by a Scheduling Coordinator to the ISO following receipt of the ISO's Suggested Adjusted Schedule.
RMR Owner	The provider of services under a Reliability Must-Run Contract.
Real-Time Dispatch (RTD) Software	The security constrained optimal dispatch and ex post pricing software used by the ISO to determine which Ancillary Service and Supplementary Energy resources to Dispatch and to calculate the Ex Post Prices.
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.
Scaled Marginal Loss Rate	A factor calculated by the ISO for a given Generator location for each hour by multiplying the Full Marginal Loss Rate for such Generator location by the Loss Scale Factor for the relevant hour.
Schedule	A statement of (i) Demand, including quantity, duration and Take-Out Points and (ii) Generation, including quantity, duration, location of Generating Unit, and Transmission Losses; and (iii) Ancillary Services which will be self-provided, (if any) submitted by a Scheduling Coordinator to the ISO. "Schedule" includes Preferred Schedules, Suggested Adjusted Schedules, Final Schedules and Revised 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	A Generator, Eligible Customer or End-User that is not an ISO Metered Entity.

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.
Scoping Meeting	The meeting among representatives of the Interconnection Customer, the applicable Participating TO, and the ISO conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.
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.
Service Area	An area in which an IOU or a Local Publicly Owned Electric Utility is 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.

Settlement	Process of financial settlement for products and services purchased and sold undertaken by the ISO under Section 11 of the ISO Tariff. Each Settlement will involve a price and a quantity.
Settlement Account	An Account held at a bank situated in California, designated by a Scheduling Coordinator or a Participating TO pursuant to the Scheduling Coordinator's SC Agreement or in the case of a Participating TO, Section 2.2.1 of the TCA, to which the ISO shall pay amounts owing to the Scheduling Coordinator or the Participating TO under the ISO Tariff.
Settlement Interval	The time period, which is equal to or a multiple of the Dispatch Interval, over which the ISO settles deviations in Generation and Demand from Final Hour-Ahead Schedules.
Settlement Period	For all ISO transactions the period beginning at the start of the hour, and ending at the end of the hour. There are twenty-four Settlement Periods in each Trading Day, with the exception of a Trading Day in which there is a change to or from daylight savings time.
Settlement Quality Meter Data	Meter Data gathered, edited, validated, and stored in a settlement-ready format, for Settlement and auditing purposes.
Settlement Statement	Either or both of a Preliminary Settlement Statement or Final Settlement Statement.
Settlement Statement Re-run	The re-calculation of a Settlement Statement in accordance with the provisions of the ISO Tariff including any protocol of the ISO.
Settlements, Metering, and Client Relations Charge	The component of the Grid Management Charge that provides for the recovery of the ISO's costs, including, but not limited to the costs of maintaining customer account data, providing

account information to customers, responding to customer inquiries, calculating market charges, resolving customer disputes, and the costs associated with the ISO's Settlement, billing, and metering activities. Because this is a fixed charge per Scheduling Coordinator ID, costs associated with activities listed above also are allocated to other charges under the Grid Management Charge according to formula set forth in Appendix F, Schedule 1, Part A of this Tariff.

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.
Site Control	Documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.
Scheduling and Logging system for the ISO of California (SLIC)	A logging application that allows Market Participants to notify the ISO when a unit's properties change due to physical problems. Users can modify the maximum and minimum output of a unit, as well as the ramping capability of the unit.
Small Generating Facility	A Generating Facility that has a Generating Facility Capacity of no more than 20 MW.
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.

Stand Alone Network Upgrades Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the ISO Controlled Grid or Affected Systems during their construction. The Participating TO, the ISO, and the Interconnection Customer must agree as to what constitutes Stand Alone

	Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.
Standard Large Generator Interconnection Agreement (LGIA	The form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility.
Standard Large Generator Interconnection Procedures (LGIP)	The ISO Protocol that sets forth the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the ISO Tariff.
Standard Ramp (-ing)	A ramp calculated from two consecutive Final Hour Ahead Schedules that results in a straight trajectory between 10 minutes before the start of an operating hour to 10 minutes after the start of the operating hour
Standby Rate	A rate assessed a Standby Service Customer by the Participating TO that also provides retail electric service, 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 that also provides retail electric service, 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 also provides retail electric service 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.

Start-Up Cost Charge	The charge determined in accordance with Section 2.5.23.3.7.
Start-Up Cost Demand	The level of Demand specified in Section 2.5.23.3.7.3.
Start-Up Cost Invoice	The invoice submitted to the ISO in accordance with Section 2.5.23.3.7.6.
Start-Up Cost Trust Account	The trust account established in accordance with Section 2.5.23.3.7.2.
Start-Up Costs	The cost incurred by a particular Generating Unit from the time of first fire, the time of receipt of an ISO Dispatch instruction, or the time the unit was last synchronized to the grid, whichever is later, until the time the generating unit reaches its minimum operating level. Start-Up Costs are determined as the sum of (1) the cost of auxiliary power used during the start-up and (2) the number that is determined multiplying the actual amount of fuel consumed by the proxy gas price as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas.

SUDC (Small Utility Distribution Company An entity that owns a Distribution System that is capable of transmitting or delivery of Energy to and/or from the ISO Controlled Grid that provides retail electric service to End-Use Customers, and has the following characteristics:

1. Annual peak Demand is 25 MW or less;
2. The Distribution System is not in a local reliability area defined by the ISO; and
3. Good Utility Practice was used in designing all substation facilities that are owned or operated by the entity and interconnected to the ISO Controlled Grid, and none of those substations have transmission circuit breakers.

Suggested Adjusted Schedule The output of the ISO's initial Congestion Management for each Scheduling Coordinator for the Day-Ahead Market ("Suggested Adjusted Day-Ahead Schedule") or for the Hour-Ahead Market ("Suggested Adjusted Hour-Ahead Schedule"). These Schedules will reflect ISO suggested adjustments to each Scheduling Coordinator's Preferred Schedule to resolve Inter-Zonal Congestion on the ISO Controlled Grid, based on the Adjustment Bids submitted. These Schedules will be balanced with respect to Generation, Transmission Losses, Load, and trades between Scheduling Coordinators to resolve Inter-Zonal Congestion.

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 and for which Scheduling Coordinators have submitted bids to the ISO at least half an hour before the commencement of the Settlement Period.

Supply The rate at which Energy is delivered to the ISO Controlled Grid measured in units of watts or standard multiples thereof, e.g., 1,000W=1 KW; 1,000 KW = 1MW, etc.

System Emergency	Conditions beyond the normal control of the ISO that affect the ability of the ISO Control Area to function normally including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment damage, or tripping of system elements which might result in cascading Outages or to restore system operation to meet the minimum operating reliability criteria.
System Planning Studies	Reports summarizing studies performed to assess the adequacy of the ISO Controlled Grid as regards conformance to Reliability Criteria.
System Reliability	A measure of an electric system's ability to deliver uninterrupted service at the proper voltage and frequency.
System Resource	A group of resources, single resource, or a portion of a resource located outside of the ISO Control Area, or an allocated portion of a Control Area's portfolio of generating resources that are directly responsive to that Control Area's Automatic Generation Control (AGC) capable of providing Energy and/or Ancillary Services to the ISO Controlled Grid.
System Unit	One or more individual Generating Units and/or Loads within a Metered Subsystem controlled so as to simulate a single resource with specified performance characteristics, as mutually determined and agreed to by the MSS Operator and the ISO. The Generating Units and/or Loads making up a System Unit must be in close physical proximity to each other such that the operation of the resources comprising the System Unit does not result in significant differences in flows on the ISO Controlled Grid.

TAC Area A portion of the ISO Controlled Grid with respect to which Participating TOs' High Voltage Transmission Revenue Requirements are recovered through a High Voltage Access Charge. TAC Areas are listed in Schedule 3 of Appendix F.

Take-Out Point	The metering points at which a Scheduling Coordinator Metered Entity or ISO Metered Entity takes delivery of Energy.
Tax Exempt Debt	Municipal Tax Exempt Debt or Local Furnishing Bonds.
Tax Exempt Participating TO	A Participating TO that is the beneficiary of outstanding Tax Exempt Debt issued to finance any electric facilities, or rights associated therewith, which are part of an integrated system including transmission facilities the Operational Control of which is transferred to the ISO pursuant to the TCA.
TCA (Transmission Control Agreement)	The agreement between the ISO and Participating TOs establishing the terms and conditions under which TOs will become Participating TOs and how the ISO and each Participating TO will discharge their respective duties and responsibilities, as may be modified from time to time.
Tie Point Meter	A revenue meter, which is capable of providing Settlement Quality Meter Data, at a Scheduling Point or at a boundary between UDCs within the ISO Controlled Grid.
TO (Transmission Owner)	An entity owning transmission facilities or having firm contractual rights to use transmission facilities.
TO Tariff	A tariff setting out a Participating TO's rates and charges for transmission access to the ISO Controlled Grid and whose other terms and conditions are the same as those contained in the document referred to as the Transmission Owners Tariff approved by FERC as it may be amended from time to time.
Tolerance Band	The tolerance band expressed in terms of Energy (MWh) for the performance requirement for Generating Units, System Units and imports from dynamically scheduled System Resources for each Settlement Interval will equal the greater of

the absolute value of: 1) 5 MW divided by number of Settlement Intervals per Settlement Period or 2) three percent (3%) of the relevant Generating Unit's, dynamically scheduled System Resource's or System Unit's maximum output (Pmax), as registered in the Master File, divided by number of Settlement Intervals per Settlement Period. The maximum output (Pmax) of a dynamically scheduled System Resource will be established by agreement between the ISO and the Scheduling Coordinator representing the System Resource on an individual case basis, taking into account the number and size of the generating resources, or allocated portions of generating resources, that comprise the System Resource.

The tolerance band expressed in terms of Energy (MWh) for the performance requirement for Participating Loads for each Settlement Interval will equal the greater of the absolute value of: 1) 5 MW divided by number of Settlement Intervals per Settlement Period or 2) three percent (3%) of the applicable Final Hour-Ahead Schedule or ISO Dispatch amount divided by number of Settlement Intervals per Settlement Period.

The Tolerance Band shall not be applied to non-dynamically scheduled System Resources.

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.

Transition Charge The component of the Access Charge collected by the ISO with the High Voltage Access Charge in accordance with Section 5.7 of Appendix F, Schedule 3.

Transition Period The period of time established by the California Legislature and CPUC to allow IOUs and Local Publicly Owned Electric Utilities an opportunity to recover Transition Costs or Severance Fees.

Transmission Losses Energy that is lost as a natural part of the process of transmitting Energy from Generation to Load delivered at the ISO/UDC boundary or Control Area boundary.

Transmission Revenue Credit For an Original Participating TO, the proceeds received from the ISO for(1) the sum of: (a) Wheeling service, (b) the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the ISO's rules and protocols, (c) Usage Charge revenues received by the Participating TO (but not those attributable to the Participating TO as a FTR Holder), plus (d) FTR auction revenues received by the Participating TO; minus (2) any charges attributable to the Participating TO (but not those attributable to the Participating TO as a FTR Holder) pursuant to Section 7.3.1.7. For a New Participating TO during the 10-year transition period described in Section 4 of Schedule 3 of Appendix F, the proceeds received from the ISO for Wheeling service and Net FTR Revenue, plus the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the ISO's rules and protocols. After the 10-year transition period, the New Participating TO Transmission

	Revenue Credit shall be calculated the same as the Transmission Revenue Credit for the Original Participating TO.
TRBA (Transmission Revenue Balancing Account)	A mechanism to be established by each Participating TO which will ensure that all Transmission Revenue Credits and other credits specified in Sections 6 and 8 of Appendix F, Schedule 3, flow through to transmission customers.

TRR (Transmission Revenue Requirement)	The TRR is the total annual authorized revenue requirements associated with transmission facilities and Entitlements turned over to the Operational Control of the ISO by a Participating TO. The costs of any transmission facility turned over to the Operational Control of the ISO shall be fully included in the Participating TO's TRR. The TRR includes the costs of transmission facilities and Entitlements and deducts Transmission Revenue Credits and credits for Standby Transmission Revenue and the transmission revenue expected to be actually received by the Participating TO for Existing Rights and Converted Rights.
Trial Operation	The period during which Interconnection Customer is engaged in on-site test operations and commissioning of a Generating Unit prior to Commercial Operation.
Trustee	The trustee of the California Independent System Operator trust established by order of the California Public Utilities Commission on August 2, 1996 Decision No. 96-08-038 relating to the Ex Parte Interim Approval of a Loan Guarantee and Trust Mechanism to Fund the Development of an Independent System Operator (ISO) and a Power Exchange (PX) pursuant to Decision 95-12-063 as modified.
UDC (Utility Distribution Company)	An entity that owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, and that provides regulated retail electric service to Eligible Customers, as well as regulated procurement service to those End-Use Customers who are not yet eligible for direct access, or who choose not to arrange services through another retailer.

Unaccounted for Energy (UFE)	UFE is the difference in Energy, for each utility Service Area and Settlement Period, between the net Energy delivered into the utility Service Area, adjusted for utility Service Area Transmission Losses (calculated in accordance with Section 7.4.2), and the total metered Demand within the utility 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).
Usage Charge	The amount of money, per 1 kW of scheduled flow, that the ISO charges a Scheduling Coordinator for use of a specific Congested Inter-Zonal Interface during a given hour.

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, Replacement 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, Market Participants and the public in relation to the status and operation of the ISO Controlled Grid.
Western Path 15	The Western Area Power Administration, Sierra Nevada Region (or its successor) with respect solely to its rights and interests in the Path 15 Upgrade.
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, the WECC.
WECC (Western Electricity Oversight Council)	The Western Electricity 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.
Zone	A portion of the ISO Controlled Grid within which Congestion is expected to be small in magnitude or to occur infrequently. "Zonal" shall be construed accordingly.

Zonal Settlement Interval Ex Post Price

The Zonal Settlement Interval Ex Post Price in a Settlement Interval in each Zone will equal the absolute-value Energy-weighted average of the Dispatch Interval Ex Post Prices in each Zone, where the weights are the system total Instructed Imbalance Energy, except Regulation Energy, for the Dispatch Interval.

ISO TARIFF APPENDIX B

Scheduling Coordinator Agreement

Scheduling Coordinator Agreement

THIS AGREEMENT is made this ___ day of _____, _____ and is entered into, by and between:

(1) [Full legal name] having a registered or principal executive office at [address] (the "Scheduling Coordinator")

and

(2) **CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION**, a California nonprofit public benefit Corporation having a principal executive office located at such place in the State of California as the ISO Governing Board may from time to time designate (the "ISO").

Whereas:

A. The Scheduling Coordinator has applied for certification by the ISO under the certification procedure referred to in Section 2.2.3 of the ISO Tariff.

B. The Scheduling Coordinator wishes to schedule Energy and Ancillary Services on the ISO Controlled Grid under the terms and conditions set forth in the ISO Tariff.

NOW IT IS HEREBY AGREED as follows:

1. **Definitions**

A. Terms and expressions used in this Agreement shall have the same meanings as those contained in the Master Definitions Supplement to the ISO Tariff.

B. The "ISO Tariff" shall mean the ISO Operating Agreement and Tariff as amended from time to time, together with any Appendices or attachments thereto.

2. **Covenant of the Scheduling Coordinator**

The Scheduling Coordinator agrees that:

A. the ISO Tariff governs all aspects of scheduling of Energy and Ancillary Services on the ISO Controlled Grid, including (without limitation), the financial and technical criteria for Scheduling Coordinators, bidding, settlement, information reporting requirements and confidentiality restrictions;

B. it will abide by, and will perform all of the obligations under the ISO Tariff placed on Scheduling Coordinators in respect of all matters set forth therein including, without limitation, all matters relating to the scheduling of Energy and Ancillary Services on the ISO Controlled Grid, ongoing obligations in respect of scheduling, Settlement, system security policy and procedures to be developed by the ISO from time to time, billing and payments, confidentiality and dispute resolution;

C. it shall ensure that each UDC, over whose Distribution System Energy or Ancillary Services are to be transmitted in accordance with Schedules, Adjustment Bids or bids for Ancillary Services submitted to the ISO by the Scheduling Coordinator, enters into a UDC operating agreement in accordance with Section 4 of the ISO Tariff;

D. it shall ensure that each Generator for which it schedules Energy or on whose behalf it submits to the ISO Adjustment Bids or bids for Ancillary Services enters into a Generator agreement in accordance with Section 5 of the ISO Tariff;

E. it shall have the primary responsibility to the ISO, as principal, for all Scheduling Coordinator payment obligations under the ISO Tariff;

F. its status as a Scheduling Coordinator is at all times subject to the ISO Tariff.

3. **Term and Termination**

3.1 This Agreement shall commence on the later of (a) _____ or (b) the date the Scheduling Coordinator is certified by the ISO as a Scheduling Coordinator.

3.2 This Agreement shall terminate upon acceptance by FERC of a notice of termination. The ISO Shall timely file any notice of termination with FERC.

4. **Assignment**

Either party may assign its obligations under this Agreement with the other party's consent, such consent shall not to be unreasonably withheld**.**

5. **Partial Invalidity**

If any provision of this Agreement, or the application of such provision to any persons, circumstance or transaction, shall be held invalid, the remainder of this Agreement, or the application of such provision to other persons or circumstances or transactions, shall not be affected thereby.

6. **Settlement Account**

The Scheduling Coordinator shall maintain at all times an account with a bank capable of Fed-Wire transfer to which credits or debits shall be made in accordance with the billing and Settlement provisions of Section 11 of the ISO Tariff. Such account shall be the account referred to in Clause 7 hereof or as notified by the Scheduling Coordinator to the ISO from time to time by giving at least 7 days written notice before the new account becomes operational.

7. **Notices**

Any notice, demand or request made to or by either party regarding this Agreement shall be made in accordance with the ISO Tariff and unless otherwise stated or agreed shall be made to the representative of the other party indicated below.

ISO:

Name of Primary Representative:_____

Name of Alternative Representative:_____

Address: _____

_____

State:_____ Zip Code: _____

E-Mail Address: _____

Phone No: _____

Fax No:_____

Scheduling Coordinator:

Name of Primary Representative: _____

Name of Alternative Representative: _____

Address: _____

State: _____ Zip Code:_____

E-Mail Address: _____

Phone No:_____

Fax No:_____

Settlement Account No:_____

Title:_____

Sort Code:_____

Bank:_____

8. **Agreement to be bound by ISO Tariff.**

The ISO Tariff is incorporated herein and made a part hereof. In the event of a conflict between the terms and conditions of this Agreement and any other terms and conditions set forth in the ISO Tariff, the terms and conditions of the ISO Tariff shall prevail.

9. **Electronic Contracting.**

All submitted applications, schedules, bids, confirmations, changes to information on file with the ISO and other communications conducted via electronic transfer (e.g. direct computer link, FTP file transfer, bulletin board, e-mail, facsimile or any other means established by the ISO) shall have the same legal rights, responsibilities, obligations and other implications as set forth in the terms and conditions of the ISO Tariff and Protocols as if executed in written format.

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

ISO:

By: _____ _____ _____
Name Title Date

Scheduling Coordinator:

By: _____ _____ _____
Name Title Date

ISO TARIFF APPENDIX C

ISO Scheduling Process

Day-Ahead Schedule Timeline

	Responsible Parties					
Line	**Time (Before or on)**	**ISO**	**SCs**	**Must-Take and Reliability generation**	**UDC**	**Actions**
	Two days ahead					
0	6:00 PM	x				Publish forecasted transmission conditions (Generator Meter Multipliers, system load forecast (by Zones), estimated Ancillary Service requirements, scheduled transmission Outages, Loop Flows, congestion, ATC, etc.)
	One day ahead					
1	5:00 AM	X				Notify Scheduling Coordinators of unit-specific Reliability Must Run requirements
2	6:00 AM	x				Update system load forecast and Ancillary Service requirements.
3			X			Notify ISO of price option for Reliability Must-Run Units for which notification was provided at 5:00 a.m.
4			x			Provide direct access load forecasts to the ISO.
5	6:30 AM	x				Provide net direct access load forecasts to UDCs.
6[not used]						
7 [not used]						
8 [not used]						
9 [not used]						
10			x			Submit initial preferred energy schedules to the ISO.
11			x			Submit Ancillary Service bids and/or self-provided Ancillary Service schedules to the ISO.
12	10:00 AM	x				Validate all SC energy schedules, including RMR requirements, and bids; notify and resolve incorrect schedules and bids, if any.

13		x				Validate all SC Ancillary Service schedules and bids; notify and resolve incorrect Ancillary Service schedules and bids, If any.
14		x				Start the Inter-Zonal Congestion Management evaluation process and Ancillary Services bid evaluation.
15	11:00 AM	x				If no Inter-Zonal Congestion exists, go to line 27.
16		x				Complete advisory dispatch schedules and transmission prices if Inter-Zonal Congestion exists.
17		x				Complete the advisory schedules and prices of each Ancillary Service.
18		x				Notify all SC if Inter-Zonal Congestion exists. Publish advisory transmission prices.
19		x				Inform all SCs their advisory dispatch schedules if Inter-Zonal Congestion exists.
20		x				Inform all SCs advisory AS schedules and prices if Inter-Zonal Congestion exists.
21	11:05 PM		x			Start the process of developing revised schedules and price bids.
22			x			Start the process of developing revised AS schedules and price bids.
23	12:00 PM		x			Submit revised Preferred Schedules and price bids to the ISO.
24			x			Submit revised preferred AS schedules and price bids to the ISO.
25	12:00 PM	x				Validate all SC schedules and bids; notify and resolve incorrect schedules and bids, if any.
26		x				Validate all SC AS schedules and bids; notify and resolve incorrect schedules and bids, if any.
27		x				Start the Inter-Zonal Congestion Management evaluation process and Ancillary Services bid evaluation.

28	1:00 PM	x				Complete final dispatch schedules and transmission prices.
29		x				Complete Final Schedules and prices of each Ancillary Service.
30	1:00 PM	x				Complete Final Schedules.
31	1:00 PM	x				Inform all SCs their final dispatch schedules.
32		x				Inform all SCs their final AS schedules and prices.
33		x				Publish transmission prices if Inter-Zonal Congestion exists.
34		x				Calculate and communicate with SC the specific SCs Zonal prices if asked.
35 [not used]						
36 [not used]						
37 [not used]						
38		x				Develop net schedules for each of the Control Area interfaces. These interfaces include SC net schedules, Control Area net schedules and/or individual transactions.
39		x				Call each adjacent Control Area and check that net schedules at each interface point match. Search for discrepancies and identify transactions that do not match. Resolve discrepancies with the involved SCs or eliminate the transactions with discrepancies.

ISO TARIFF APPENDIX D

Black Start Units

Black Start Units

The following requirements must be met by Generating Units providing Black Start ("Black Start Units"):

(a) Black Start Units must be capable of starting and paralleling with the ISO Controlled Grid without aid from the ISO Controlled Grid;

(b) Black Start Units must be capable of making a minimum number of starts per event (to be without aid from the ISO Controlled Grid as determined by the ISO);

(c) Black Start Units must be equipped with governors capable of operating in the stand alone (asynchronous) and parallel (synchronous) modes.

(d) Black Start Units must have startup load pickup capabilities at a level to be determined by the ISO, including total startup load (MW) and largest startup load (MW) for such power output levels as the ISO may specify.

(e) All Black Start Units must be capable of producing Reactive Power (boost) and absorbing Reactive Power (buck) as required by the ISO to control system voltages. This requirement may be met by the operation of more than one Black Start Unit in parallel providing that:

(i) the Black Start generation supplier demonstrates that the proposed Generation resource shares reactive burden equitably;

(ii) all Participating Generators associated with the proposed Black Start source are located in the same general area.

Buck/boost capability requirement shall be dependent on the location of the proposed resource in relation to Black Start load.

(f) All Black Start Units must have the following communication/control requirements:

(i) dial-up telephone;

(ii) backup radio;

(iii) manning levels which accord with Good Utility Practice.

ISO TARIFF APPENDIX E

Verification of Submitted Data for Ancillary Services

Verification of Submitted Data for Ancillary Services

The ISO shall use the following procedures for verifying the scheduling and bid information submitted by Scheduling Coordinators for Ancillary Services. In this Appendix, a "bid" is a bid submitted by a Scheduling Coordinator in the ISO's competitive Ancillary Services market. A "schedule" is a Schedule including Ancillary Services which the Scheduling Coordinator wishes to self-provide.

1. Bid File and Schedule Format. The ISO shall verify that the bid files and schedules conform to the format specified for the type of Ancillary Service bid or schedule submitted. If the bid file or schedule does not conform to specifications, it shall be annotated by the ISO to indicate the location of the errors, and returned to the Scheduling Coordinator for corrections. Any changes made by a Scheduling Coordinator shall require a new submittal of bid or schedule information, and all validity checks shall be performed on the re-submitted bid or schedule.

2. Generation Schedules and Bids.

2.1. Quantity Data. The ISO shall verify that no Scheduling Coordinator is submitting a scheduled or bid quantity for Regulation, Spinning Reserve, Non-Spinning or Replacement Reserve which exceeds available capacity for Regulation and Reserves on the Generating Units, Loads and resources scheduled for that Settlement Period.

2.2 Location Data. The ISO shall verify that the location data corresponds to the ISO Controlled Grid interconnection data.

2.3. Operating Capability. The ISO shall verify that the operating capability data corresponds to the ISO Controlled Grid interconnection data for each Generating Unit, Load or other resource for which a Scheduling Coordinator is submitting an Ancillary Service bid or schedule.

3. Load Schedules and Bids.

3.1. Quantity data. The ISO shall verify that the quantity of Non-Spinning and Replacement Reserve scheduled or bid from Dispatchable Load does not exceed scheduled consumption quantities for that Settlement Period.

3.2. Location data. The ISO shall verify that the location of the Dispatchable Load corresponds to the ISO Controlled Grid interconnection data for each supplier of Dispatchable Load.

4. Notification of Validity or Invalidity of Ancillary Services Schedules and Competitive Bids. The ISO shall, as soon as reasonably practical following the receipt of competitive bids or self-provided Ancillary Service schedules, send to the Scheduling Coordinator who submitted the schedule or bid the following information:

(a) acknowledgment of receipt of the competitive bid or self-provided Ancillary Service schedule;

(b) notification that the bid or schedule has been accepted or reject for non-compliance with the rules specified in this Appendix. If a bid or schedule is rejected, such notification shall contain an explanation of why the bid or schedule was not accepted;

(c) a copy of the bid or schedule as processed by the ISO.

In response to an invalid schedule or bid, the Scheduling Coordinator shall be given a period of time to respond to the notification. The Scheduling Coordinator shall respond by resubmitting a corrected schedule or bid. If the Scheduling Coordinator does not respond to the notification within the required time frame, the ISO shall proceed without that Scheduling Coordinator's bid or schedule.

5. Treatment of Missing Values.

5.1 Missing Location Values. Any bid submitted without a Location Code shall be deemed to have a zero bid quantity for that Settlement Period.

5.2 Missing Quantity Values. Any bid submitted without a quantity value shall be deemed to have a zero bid quantity for Ancillary Service capacity for that Settlement Period.

5.3 Missing Price Values. Any bid submitted with non-zero quantity value, but with a missing price value, shall be rejected.

6. Treatment of Equal Price Bids. The ISO shall allow these Scheduling Coordinators to resubmit, at their own discretion, their bid no later than 2 hours the same day the original bid was submitted. In the event identical prices still exist following resubmission of bids, the ISO shall determine the merit order for each Ancillary Service by considering applicable constraint information for each Generating Unit, Load or other resource, and optimize overall costs for the Trading Day. If equal bids still remain, the ISO shall proportion participation in the Final Day-Ahead or Hour-Ahead Schedule (as the case may be) amongst the bidding Generating Units, Loads and resources with identical bids to the extent permitted by operating constraints and in a manner deemed appropriate by the ISO.

7. Receipt of Bids and Schedules. The ISO shall maintain an audit trail relating to the receipt of bids and schedules and the processing of those bids and schedules.

ISO TARIFF APPENDIX F

Rate Schedules

Schedule 1

Grid Management Charge

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

The Grid Management Charge consists of eight separate service charges: (1) the Core Reliability Services – Demand Charge, (2) the Core Reliability Services – Energy Exports Charge; (3) Energy Transmission Services Net Energy Charge, (4) the Energy Transmission Services Uninstructed Deviations Charge, (5) the Forward Scheduling Charge, (6) the Congestion Management Charge, (7) the Market Usage Charge, and (8) the Settlements, Metering, and Client Relations Charge.

1. The rate in $/MW for the Core Reliability Services – Demand Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered non-coincident peak hourly demand in MW for all months during the year (excluding the portion of such Demand associated with Energy Exports, if any, as may be modified in accordance with Part F of this Schedule 1), reduced by thirty-four (34) percent of the sum of all Scheduling Coordinators' metered non-coincident peaks occurring during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, including Sundays and holidays; provided that if a Scheduling Coordinator's metered non-coincident peak hour during the month occurs during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, the rate shall be sixty-six (66) percent of the standard Core Reliability Services – Demand rate.

2. The rate in $/MWh for the Core Reliability Services – Energy Export Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered volume of Energy Exports in MWh, as may be modified in accordance with Part F of this Schedule 1, for all months during the year.

3. The rate in $/MWh for the Energy Transmission Services Net Energy Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Metered Control Area Load.

4. The rate in $/MWh for the Energy Transmission Services Uninstructed Deviations Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the absolute value of total annual forecasted net uninstructed deviations (netted within a Settlement Interval summed over the calendar month) in MWh.

5. The rate in $ per Schedule for the Forward Scheduling Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted number of non-zero MW Final Hour-Ahead Schedules, as may be modified in accordance with Part F of this Schedule 1, including all awarded Ancillary Service bids; provided that the Forward Scheduling charge attributable to Final Hour-Ahead Schedules for Inter-Scheduling Coordinator Energy and Ancillary Service Trades for each

Scheduling Coordinator is fifty (50) percent of the standard Forward Scheduling Charge.

6. The rate in $/MWh for the Congestion Management Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Scheduling Coordinators' inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh.

7. The rate in $/MWh for the Market Usage Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted total purchases and sales (including out-of-market transactions) of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted within a Settlement Interval summed over the calendar month) in MWh.

8. The rate for the Settlements, Metering, and Client Relations Charge will be fixed at $500.00 per month, per Scheduling Coordinator Identification Number ("SC ID") with an invoice value other than $0.00 in the current trade month.

The rates for the foregoing charges shall be adjusted automatically each year, effective January 1 for the following twelve months, in the manner set forth in Part D of this Schedule.

Part B – Quarterly Adjustment, If Required

Each component rate of the Grid Management Charge will be adjusted automatically on a quarterly basis, up or down, so that rates reflect the annual revenue requirement as stated in the ISO's filing or posting on the ISO Home Page, as applicable, if the estimated billing determinant volumes for that component, on an annual basis, change by 5% or more during the year. Such adjustment may be implemented not more than once per calendar quarter, and will be effective the first day of the next calendar month.

The rates will be adjusted in accordance with the following formula:

According to the formulae listed in Appendix F, Schedule 1, Part A with the billing determinant(s) readjusted on a going-forward basis to reflect the 5% or greater change from the estimated billing determinant provided in the annual informational filing.

Part C – Costs Recovered through the GMC

As provided in Section 8 of the ISO Tariff, the Grid Management Charge includes the following costs, as projected in the ISO's budget for the year to which the Grid Management Charge applies:

- Operating costs (as defined in Section 8.2.2)
- Financing costs (as defined in Section 8.2.3), including Start-Up and Development costs and
- Operating and Capital Reserve costs (as defined in Section 8.2.4)

Such costs, for the ISO as a whole, are allocated to the eight service charges that comprise the Grid Management Charge: (1) Core Reliability Services - Demand Charge, (2) Core Reliability Services – Energy Export Charge, (3) Energy Transmission Services Net Energy Charge, (4) Energy Transmission Services Uninstructed Deviations Charge, (5) Forward Scheduling Charge, (6) Congestion Management Charge, (7) Market Usage Charge, and (8) Settlements, Metering, and Client Relations Charge, according to the factors listed in Part E of this Schedule 1, and

adjusted annually for:

- any surplus revenues from the previous year as deposited in the Operating and Capital Reserve Account, as defined under Section 8.5, or deficiency of revenues, as recorded in a memorandum account;

divided by:

- forecasted annual billing determinant volumes;

adjusted quarterly for:

- a change in the volume estimate used to calculate the individual Grid Management Charge components, if, on an annual basis, the change is 5% or more.

The Grid Management Charge revenue requirement formula is as follows:

Grid Management Charge revenue requirement =

- Operating Expenses + Debt Service + [(Coverage Requirement x Senior Lien Debt Service) and/or (Cash Funded Capital Expenditures)] - Interest Earnings - Other Revenues - Reserve Transfer

Where,

- **Operating Expenses** = O&M Expenses plus Taxes Other Than Income Taxes and Penalties

- **O&M Expenses** = Transmission O&M Expenses (Accounts 560-574) plus Customer Accounting Expenses (Accounts 901-905) plus Customer Service and Informational Expenses (Accounts 906-910) plus Sales Expenses (Accounts 911-917) plus Administrative & General Expenses (Accounts 920-935)
- **Taxes Other Than Income Taxes =** those taxes other than income taxes which relate to ISO operating income (Account 408.1)
- **Penalties** = payments by the ISO for penalties or fines incurred for violation of WECC reliability criteria (Account 426.3)
- **Debt Service** = for any fiscal year, scheduled principal and interest payments, sinking fund payments related to balloon maturities, repayment of commercial paper notes, net payments required pursuant to a payment obligation, or payments due on any ISO notes. This amount includes the current year accrued principal and interest payments due in April of the following year.
- **Coverage Requirement** = 25% of the Senior Lien Debt Service.
- **Senior Lien Debt Service** = all Debt Service that has a first lien on ISO Net Operating Revenues (Account 128 subaccounts).
- **Cash Funded Capital Expenditures** = Post current fiscal year capital additions (Accounts 301-399) funded on a pay-as-you-go basis.
- **Interest Earnings** = Interest earnings on Operating and Capital Reserve balances (Account 419). Interest on bond or note proceeds specifically designated for capital projects or capitalized interest is excluded.
- **Other Revenues** = Amounts booked to Account 456 subaccounts. Such amounts include but are not limited to application fees, WECC reliability coordinator reimbursements, Line Operator Charges, and fines assessed and collected by the ISO.
- **Reserve Transfer** = the projected reserve balance for December 31 of the prior year less the Reserve Requirement as adopted by the ISO Governing Board and FERC. If such amount is negative, the amount may be divided by two, so that the reserve is replenished within a two-year period. (Account 128 subaccounts)
- **Reserve Requirement** = 15% of Annual Operating Expenses.

A separate revenue requirement shall be established for each component of the Grid Management Charge by developing the revenue requirement for the ISO as a whole and then assigning such costs to the seven service categories using the allocation factors provided in Appendix F, Schedule 1, Part E of this Tariff.

Part D – Information Requirements

Budget Schedule

The ISO will convene, prior to the commencement of the Annual Budget process, an initial meeting with stakeholders to: (a) receive ideas to control ISO costs; (b) receive ideas for projects to be considered in the capital budget development process; and, (c) receive suggestions for reordering ISO priorities in the coming year.

Within 2 weeks of the initial meeting, the ideas presented by the stakeholders shall be communicated in writing to the ISO's officers, directors and managers as part of the budget development process, and a copy of this communication shall be made available to stakeholders.

Subsequent to the initial submission of the draft budget to the finance committee of the ISO Governing Board, the ISO will provide stakeholders with the following information: (a) proposed capital budget with indicative projects for the next subsequent calendar year, a budget-to-actual

review for capital expenditures for the previous calendar year, and a budget-to-actual review of current year capital costs; and, (b) expenditures and activities in detail for the next subsequent calendar year (in the form of a draft of the budget book for the ISO Governing Board), budget-to-actual review of expenditures and activities for the previous calendar year, and a budget-to-actual review of expenditures for the current year. Certain of this detailed information which is deemed commercially sensitive will only be made available to parties that pay the ISO's GMC (or regulators) who execute a confidentiality agreement.

The ISO shall provide such materials on a timely basis to provide stakeholders at least one full committee meeting cycle to review and prepare comments on the draft annual budget to the finance committee of the ISO Governing Board.

At least one month prior to the ISO Governing Board meeting scheduled to consider approval of the proposed budget, the ISO will hold a meeting open to all stakeholders to discuss the details of the ISO's budget and revenue requirement for the forthcoming year. To the extent that such a meeting will deal with complex matters of budgetary and policy import, the ISO will endeavor to host a workshop on the ISO's budget preparation process in advance of the meeting to better prepare stakeholders.

Prior to a final recommendation by the finance committee of the ISO Governing Board on the ISO's draft annual budget, the ISO shall respond in writing to all written comments on the draft annual budget submitted by stakeholders and/or the ISO shall issue a revised draft budget indicating in detail the manner in which the stakeholders' comments have been taken into consideration.

The ISO will provide no fewer than 45 days for stakeholder review of its annual budget between initial budget posting and final approval of the budget by the ISO Governing Board.

Budget Posting

After the approval of the annual budget by the ISO Governing Board, the ISO will post on its Internet site the ISO operating and capital budget to be effective during the subsequent fiscal year, and the billing determinant volumes used to develop the rate for each component of the Grid Management Charge, together with workpapers showing the calculation of such rates.

Annual Filing

If the Grid Management Charge revenue requirement for Budget Year 2005 does not exceed $218.4 million or its revenue requirement for Budget Year 2006 does not exceed $221.7 million, the ISO shall not be required to make a Section 205 filing to adjust the GMC charges calculated in accordance with this Schedule 1 to collect such Revenue Requirement. In order for the ISO to adjust the GMC charges to collect a Grid Management Charge revenue requirement for Budget Year 2005 that exceeds $218.4 million or Budget Year 2006 that exceeds $221.7 million, the ISO must submit an application to the FERC under Section 205. In any event, the ISO shall submit a filing under Section 205 for approval of the GMC charges to be effective as of January 1, 2007. In such filing, the ISO may revise the GMC rates set forth in this Schedule 1, but shall not be required to do so.

Periodic Financial Reports

The ISO will create periodic financial reports consisting of an income statement, balance sheet, statement of operating reserves, and such other reports as are required by the ISO Governing Board. The periodic financial reports will be posted on the ISO's Website not less than quarterly.

Part E – Cost Allocation

1. The Grid Management Charge revenue requirement, determined in accordance with Part C of this Schedule 1, shall be allocated to the eight service charges specified in Part A of this Schedule 1 as follows, subject to Section 2 of this Part E. Expenses projected to be recorded in each cost center shall be allocated among the eight charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E. In the event the ISO budgets for projected expenditures for cost centers are not specified in Table 1 to Schedule 1, such expenditures shall be allocated based on the allocation factors for the respective ISO division hosting that newly-created cost center. Such divisional allocation factors are specified in Table 1 to this Schedule 1.

Debt service expenditures for the ISO's year 2000 (or subsequently refinanced) bond offering shall be allocated among the eight charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E. Capital expenditures shall be allocated among the eight charges in accordance with the allocation factors listed in Table 2 to this Schedule 1, subject to Section 2 of this Part E, for the system for which the capital expenditure is projected to be made.

Any costs allocated by the factors listed in Table 1 and Table 2 to the Settlements, Metering, and Client Relations category that would remain un-recovered after the assessment of the charge for that service specified in Section 8 of Part A of this Schedule 1 on forecasted billing determinant volumes shall be reallocated to the remaining GMC service categories in the ratios set forth in Table 3 to this Schedule 1.

2. The allocation of costs in accordance with Section 1 and Tables 1 and 2 of this Part E shall be adjusted as follows:

Costs allocated to the Energy Transmission Services category in the following tables are further apportioned to the Energy Transmission Services Net Energy and Energy Transmission Services Uninstructed Deviations subcategories in 80% and 20% ratios, respectively.

Twenty (20) percent of the costs allocated to the Forward Scheduling Charge in the following Tables shall be reallocated to the Congestion Management Charge. A portion of the costs allocated to the Forward Scheduling Charge, associated with the fifty (50) percent reduction in the standard Forward Scheduling Charge to be applied to Final Hour-Ahead Schedules for Inter-Scheduling Coordinator Energy and Ancillary Service Trades as specified in Part A of this Schedule 1, shall be reallocated to the remaining GMC service categories in the ratios set forth in Table 3 to this Schedule 1.

Table 1

O&M, Debt Service, and Other Expense Recoveries Cost Allocation Factors

CC #	Cost Center	CRS	ETS	FS	CM	MU	SMCR	Total
1100	**CEO Division**	**44.01%**	**21.51%**	**3.78%**	**4.61%**	**10.45%**	**15.63%**	**100%**
1111	CEO - General	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1241	MD02	6.95%	0%	13.86%	10.91 %	28.38%	39.90%	100%
1521	Grid Planning	62.50%	37.50%	0%	0%	0%	0%	100%
1300	**Finance Division**	**44.04%**	**21.49%**	**3.62%**	**4.22%**	**10.31%**	**16.32%**	**100%**

1311	CFO - General	44.04%	21.49%	3.62%	4.22%	10.31%	16.32%	100%
1321	Accounting	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1331	Financial Planning and Treasury	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1351	Facilities	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
1361	Security & Corporate Services	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%

1400	**Information Services Division**	**38.25%**	**7.16%**	**9.74%**	**4.78%**	**9.23%**	**30.85%**	**100%**
1411	Chief Information Officer	38.25%	7.16%	9.74%	4.78%	9.23%	30.85%	100%
1422	Corporate & Enterprise Applications	33.28%	7.06%	1.16%	25.28%	12.58%	20.63%	100%
1424	Asset Management	35.30%	6.12%	10.91%	4.88%	10.50%	32.29%	100%
1431	End User Support	37.80%	14.44%	8.29%	3.5%	9.32%	26.65%	100%
1432	Computer Operations and Infrastructure Services	34.15%	9.21%	11.76%	3.08%	8.69%	33.11%	100%
1433	Network Services	43.38%	11.88%	9.39%	2.61%	9.23%	23.51%	100%
1441	Outsourced Contracts	42.25%	10.62%	10.25%	2.53%	9.07%	25.28%	100%
1442	Production Support	25.09%	0.17%	17.98%	2.62%	7.52%	46.62%	100%
1451	Information Support Services	25.09%	0.17%	17.98%	2.62%	7.52%	46.62%	100%
1461	Control Systems	96.44%	2.44%	0%	0%	0.56%	0.56%	100%
1462	Field Data Acquisition System (FDAS)	21.43%	0%	0%	0%	0%	78.57%	100%
1463	Operations Systems Services	50.44%	2.91%	6.01%	1.21%	5.95%	33.49%	100%
1466	Enterprise Applications	47.98%	7.30%	1.19%	1.34%	3.47%	38.72%	100%
1467	Settlement Systems Services	27.34%	11.20%	1.83%	2.05%	5.32%	52.25%	100%
1468	Corporate Application Support and Administration	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
1469	Analytical and Reporting Applications	10%	0%	0%	65%	25%	0%	100%
1471	IT Planning	25.09%	0.17%	17.98%	2.62%	7.52%	46.62%	100%
1481	Markets and Scheduling System Services	46.85%	2.86%	23.68%	2.5%	17.64%	6.48%	100%
1482	Market Systems Support Services	44.94%	1.05%	18.51%	6.17%	23.78%	5.54%	100%
1500	**Grid Operations Division**	**66.71%**	**33.29%**	**0%**	**0%**	**0%**	**0%**	**100%**
1511	VP Grid Operations	66.71%	33.29%	0%	0%	0%	0%	100%
1542	Outage Coordination	95.11%	4.89%	0%	0%	0%	0%	100%
1543	Loads and Resources	48.95%	51.05%	0%	0%	0%	0%	100%
1544	Real-Time Scheduling	60%	40%	0%	0%	0%	0%	100%
1545	Grid Operations	67.47%	32.53%	0%	0%	0%	0%	100%
1546	Security Coordination	100%	0%	0%	0%	0%	0%	100%
1547	Engineering and Maintenance	46.42%	53.58%	0%	0%	0%	0%	100%

1548	OSAT Group - General	93.2%	6.80%	0%	0%	0%	0%	100%
1549	Operations Training	50.48%	49.52%	0%	0%	0%	0%	100%
1554	Special Projects Engineering	42.86%	57.14%	0%	0%	0%	0%	100%
1555	Operations Support Group	55.56%	44.44%	0%	0%	0%	0%	100%

1558	Transmission Maintenance	58.46%	41.54%	0%	0%	0%	0%	100%
1559	Operations Application Support	60%	40%	0%	0%	0%	0%	100%
1561	Operations Engineering South	65.32%	34.68%	0%	0%	0%	0%	100%
1562	Operations Engineering North	55.15%	44.85%	0%	0%	0%	0%	100%
1563	Operations Coordination	74.55%	25.45%	0%	0%	0%	0%	100%
1564	Operations Scheduling	100%	0%	0%	0%	0%	0%	100%
1565	Pre-Scheduling and Support	76.92%	23.08%	0%	0%	0%	0%	100%
1566	Regional Coordination - General	100%	0%	0%	0%	0%	0%	100%
1600	**Legal and Regulatory Division**	**35.80%**	**21.78%**	**3.73%**	**7.18%**	**16.97%**	**14.54%**	**100%**
1611	VP General Counsel - General	35.80	21.78%	3.73%	7.18%	16.97%	14.54%	100%
1631	Legal and Regulatory	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1641	Market Analysis	15.32%	26.33%	0%	19.90 %	31.38%	7.07%	100%
1642	Market Surveillance Committee	25%	25%	0%	25%	25%	0%	100%
1651	ISO Governing Board	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1661	Compliance - General	21.90%	20.37%	11.90 %	0%	28.50%	17.33%	100%
1662	Compliance - Audits	8.33%	0%	0%	0%	50%	41.67%	100%
1700	**Market Services Division**	**17.14%**	**2.43%**	**9.46%**	**9.39%**	**20.35%**	**41.23%**	**100%**
1711	VP Market Services - General	17.14%	2.43%	9.46%	9.39%	20.35%	41.23%	100%
1721	Billing and Settlements-General	25%	0%	0%	0%	0%	75%	100%
1722	Business Development Support	0%	0%	0%	0%	0%	100%	100%
1723	RMR Settlements	80.30%	19.70%	0%	0%	0%	0%	100%
1724	BBS - PSS	0%	0%	0%	0%	0%	100%	100%
1725	BBS - FSS	0%	0%	0%	0%	0%	100%	100%
1731	Contracts and Special Projects	43.17%	6.83%	0%	0%	0%	50%	100%
1741	Client Relations	0%	0%	0%	0%	0%	100%	100%
1751	Market Operations - General	30.66%	0%	15.33 %	15.33 %	34.85%	3.83%	100%
1752	Manager of Markets	27.31%	5.46%	27.31 %	21.84 %	18.08%	0%	100%
1753	Market Engineering	21.32%	0%	0%	28.43 %	43.15%	7.11%	100%
1755	Business Solutions	5.91%	0%	47.27 %	11.82 %	29.10%	5.91%	100%

1756	Market Quality - General	0%	0%	0%	0%	70.93%	29.07%	100%
1757	Market Integration	7.38%	0%	29.52%	29.52%	26.20%	7.38%	100%

1800	**Corporate and Strategic Development Division**	**44.04%**	**21.49%**	**3.62%**	**4.21%**	**10.31%**	**16.33%**	**100%**
1811	VP Corporate and Strategic Development - General	44.04%	21.49%	3.62%	4.21%	10.31%	16.33%	100%
1821	Communications	44.01%	22.51%	3.78%	4.61%	10.45%	15.63%	100%
1831	Strategic Development	44.01%	22.51%	3.78%	4.61%	10.45%	15.63%	100%
1841	Human Resources	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
1851	Project Office	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1861	Regulatory Policy	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
Other Revenue and Credits								
	SC Application and Training Fees	0%	0%	0%	0%	0%	100%	100%
	WECC Reimbursement/NERC Reimbursement	100%	0%	0%	0%	0%	0%	100%
	Interest Earnings	36.64%	12.29%	9.34%	4.97%	11.47%	25.30%	100%
Debt Service Related Allocations		33.49%	7.93%	15.26%	5.19%	9.44%	28.69%	100%

Table 2

Capital Cost Allocation Factors

System	CRS	ETS	FS	CM	MU	SMCR	Total
ACC Upgrades (Communication between ISO & IOUs)	100%	0%	0%	0%	0%	0%	100%
Ancillary Services Management (ASM) Component of SA	15%	0%	40%	0%	45%	0%	100%
Application Development Tools	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Automated Dispatch System (ADS)	50%	0%	25%	0%	20%	5%	100%
Automated Load Forecast System (ALFS)	70%	0%	10%	0%	20%	0%	100%
Automatic Mitigation Procedure (AMP)	85%	0%	0%	0%	15%	0%	100%
Backup systems (Legato/Quantum)	23%	0%	22%	3%	7%	45%	100%

Balance of Business Systems (BBS)	0%	0%	0%	0%	0%	100%	100%
Balancing Energy Ex Post Price (BEEP) Component of SA	50%	0%	20%	10%	20%	0%	100%
Bill's Interchange Schedule (BITS)	85%	0%	0%	0%	15%	0%	100%
CaseWise (process modeling tool)	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
CHASE	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Common Information Model (CIM)	100%	0%	0%	0%	0%	0%	100%
Compliance (Blaze)	19.17%	16.27%	9.5%	0%	32.83%	22.23%	100%
Congestion Management (CONG) (Component of SA)	10%	0%	0%	65%	25%	0%	100%
Congestion Reform-DSOW	50%	0%	0%	50%	0%	0%	100%
Congestion Revenue Rights (CRR)	0%	0%	0%	80%	20%	0%	100%
DataWarehouse	24.46%	18.27%	6.40%	8.74%	24.30%	17.82%	100%
Dept. of Market Analysis Tools (SAS/MARS)	15.32%	26.33%	0%	19.90%	31.38%	7.07%	100%
Dispute Tracking System (Remedy)	0%	0%	0%	0%	0%	100%	100%
Documentum	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Electronic Tagging (Etag)	100%	0%	0%	0%	0%	0%	100%
Energy Management System (EMS)	100%	0%	0%	0%	0%	0%	100%
Engineering Analysis Tools	60%	40%	0%	0%	0%	0%	100%
Evaluation of Market Separation	0%	0%	0%	50%	50%	0%	100%
Existing Transmission Contracts Calculator (ETCC)	25%	0%	20%	15%	20%	20%	100%
FERC Study Software	0%	0%	0%	0%	100%	0%	100%
Firm Transmission Right (FTR) and Secondary Registration System (SRS)	0%	0%	15%	60%	15%	10%	100%

Global Resource Reliability Management Application (GRRMA)	75%	15%	0%	0%	10%	0%	100%
Grid Operations Training Simulator (GOTS)	56%	44%	0%	0%	0%	0%	100%
Hour-Ahead Data AnalysisTool, Day-Ahead Data AnalysisTool,	0%	0%	100%	0%	0%	0%	100%
Human Resources	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
IBM Contract	37.26%	14.44%	9.54%	3.52%	9.10%	26.13%	100%
Integrated Forward Market (IFM)	10%	0%	35%	0%	55%	0%	100%
Internal Development	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Interzonal Congestion Management reform - Real Time	50%	0%	0%	50%	0%	0%	100%
Land and Building Costs	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Local Area Network (LAN)	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Locational Marginal Pricing (LMPM)	10%	0%	35%	0%	55%	0%	100%
Market Transaction System (MTS)	0%	0%	0%	0%	100%	0%	100%
Masterfile	20%	0%	20%	0%	55%	5%	100%
MD02 Capital	6.95%	0%	13.86%	10.91%	28.38%	39.90%	100%
Meter Data Acquisition System (MDAS)	0%	0%	0%	0%	0%	100%	100%
Miscellaneous (2004 related projects)	23.46%	0%	21.78%	2.68%	6.86%	45.04%	100%
Monitoring (Tivoli)	23.46%	0%	21.78%	2.68%	6.86%	45.04%	100%
New Resource Interconnection (NRI)	100%	0%	0%	0%	0%	0%	100%
New System Equipment (replacement of owned equipment)	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
NT/web servers	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
NT-servers	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%

Oracle Enterprise Manager (OEM)	27%	0.%	18%	5%	9%	41%	100%
Office Automation - desktop/laptop (OA)	44%	27%	4%	4%	10%	17%	100%
Office equipment (scanner, printer, copier, fax, Communication Equipment)	44%	21%	4%	4%	10%	17%	100%
Open Access Same Time Information System (OASIS)	10%	0%	25%	10%	35%	20%	100%
Operational Meter Analysis and Reporting (OMAR)	0%	0%	0%	0%	0%	100%	100%
Oracle Corporate Financials	44%	21%	4%	4%	10%	17%	100%
Oracle Licenses	27%	0%	18%	5%	9%	41%	100%
Oracle Market Financials BBS	0%	0%	0%	0%	0%	100%	100%
Out of Sequence Market Operation Settlements Information System (OOS)	5%	5%	0%	0%	90%	0%	100%
Outage Scheduler (OS)	50%	0%	10%	20%	20%	0%	100%
Participating Intermittent Resource Project (PIRP)	0%	0%	93.92%	0%	6.08%	0%	100%
Physical Facilities Software Application/Furniture/Leasehold Improvements	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Process Information System (PI)	80%	0%	0%	0%	10%	10%	100%
Rational Buyer	100%	0%	0%	0%	0%	0%	100%
Real Time Energy Dispatch System (REDS)	100%	0%	0%	0%	0%	0%	100%
Real Time Nodal Market	35%	0%	10%	0%	55%	0%	100%
Reliability Management System (RMS)	100%	0%	0%	0%	0%	0%	100%
Remedy (related to Transmission Registry, New Resource Interconnection, and Resource Registry)	100%	0%	0%	0%	0%	0%	100%
Remote Intelligent Gateway (RIG) & Data Processing Gateway (DPG)	100%	0%	0%	0%	0%	0%	100%
Resource Register (RR)	100%	0%	0%	0%	0%	0%	100%

RMR Application Validation Engine (RAVE)	100%	0%	0%	0%	0%	0%	100%
Scheduling & Logging for ISO California (SLIC)	65%	0%	15%	5%	15%	0%	100%
Scheduling Architecture (SA)	23.96%	0%	19.84%	25.87%	30.33%	0%	100%
Scheduling Infrastructure (SI)	0%	0%	93.92%	0%	6.08%	0%	100%
Scheduling Infrastructure Business Rules (SIBR)	0%	0%	93.92%	0%	6.08%	0%	100%
Security Constrained Economic Dispatch (SCED)	40%	0%	0%	0%	60%	0%	100%
Security- External/Physical	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Security-ISS (CUDA)	23%	0%	22%	3%	7%	45%	100%
Settlements and Market Clearing	0%	0%	0%	0%	0%	100%	100%
Sign Board (Symon Board maint.)	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Startup Costs through 3/31/98, Working Capital-3 months	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Storage (EMC symmetrix)	18.67%	9.55%	13.71%	4.21%	11.77%	42.09%	100%
System Equipment Buyouts (lease buyouts)	43.27%	1.02%	7.34%	1.79%	11.03%	35.56%	100%
Telephone/PBX	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Training Systems	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Transmission Constrained Unit Commitment (TCUC) Must Offer Obligation	100%	0%	0%	0%	0%	0%	100%
Transmission Map Plotting & Display	50%	50%	0%	0%	0%	0%	100%
Trustee Costs, Interest-Capitalized, User Groups	53.60%	0.55%	10.62%	15.74%	17.48%	2%	100%
Utilities - System i.e. Print drivers	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Vitria (Middleware)	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Wide Area Network (WAN)	40.80%	2.14%	18.68%	1.31%	7.60%	29.48%	100%

Capital Expenditures for Systems not Specified	32.20%	7.40%	15%	5.50%	10.60%	29.30%	100%

Table 3

Reallocation Factors for Projected Unrecovered Portion of Settlements, Metering, and Client Relations Revenue Requirement

	CRS	ETS	FS	CM	MU	SMCR	Total
Functional Association of Settlements, Metering, and Client Relations	0.0%	70.34%	0.0%	8.23%	21.43%	0.0%	100.0%

Part F – Other Modifications to the Rates

Consistent with a Settlement Agreement accepted by the FERC in Docket Nos. ER04-115-000, et al., GMC rates and charges shall be calculated consistent with the following additional requirements during the period that the GMC rates and charges specified in that Settlement Agreement remain in effect:

1. The GMC chargeable to a Scheduling Coordinator for transactions representing transfers from the Mohave generation facility to the Loads of the Mohave co-owners located outside of the ISO Control Area, will be reduced by excluding 65 percent of those Loads from the Energy Transmission Services Net Energy Charge and the Core Reliability Services – Energy Exports Charge. Such excluded Load shall not be included in the denominators used to calculate the rates for the Energy Transmission Services – Net Energy Charge and the Core Reliability Services – Energy Export Charge.

2. The Forward Scheduling Charge assessed against Schedules submitted by PG&E solely in its role as Path 15 facilitator will be reduced by excluding 65 percent of the number of such Schedules from the Forward Scheduling Charge. Such excluded Schedules shall not be included in the denominator upon which the Forward Scheduling Charge is calculated.

3. Modesto Irrigation District (MID) is a Scheduling Coordinator and also is responsible for a portion of the GMC charges payable by another Scheduling Coordinator, Pacific Gas and Electric Company (PG&E) pursuant to a contract between them. MID and PG&E have agreed that MID shall pay the ISO directly $75,000 each month, in lieu of any payments to PG&E for its share of the GMC charges payable by PG&E and the ISO shall credit a portion of the amount received from MID to PG&E as an offset to PG&E's obligation for GMC charges. Any difference, positive or negative, between the amount credited to PG&E and the amount paid by MID to the ISO under this provision shall be reflected in the Operating and Capital Reserves Account. The payment arrangement described in this paragraph is subject to the conditions, and will be implemented pursuant to the procedures, set forth in the Offer of Partial Settlement accepted by the FERC in Docket Nos. ER04-115-000, et al. This arrangement shall not apply to MID's obligation for GMC charges as a Scheduling Coordinator, which shall be governed by the provisions of this Schedule 1 and the other applicable provisions of the ISO Tariff, except that in the event that MID accepts responsibility for scheduling any load currently scheduled by PG&E

under SCID PGAB, the ISO will not charge any additional GMC at the tariffed GMC rate, but rather will attribute such schedules and load to the fixed $75,000.00 per month payment set forth above, provided that MID schedules such load under a new and separate SCID and the ISO shall not assess GMC charges to such SCID.

4. San Diego Gas & Electric is the Scheduling Coordinator for transactions on those portions of the Southwest Power Link ("SWPL") which are owned by the Arizona Public Service Company ("APS") and the Imperial Irrigation District ("IID"), and are scheduled by SDG&E under a designated SCID. Schedules submitted to the ISO under that designated SCID shall not be subject to GMC charges. In lieu of GMC charges, SDG&E will pay the ISO a Line Operator Charge, as agreed to in the SWPL Operations Agreement, entered into by the ISO and SDG&E on May 23, 2005, and submitted to the Commission as a rate schedule pursuant to the Federal Power Act.

Schedule 2

Other Charges

Voltage Support Service

The user rate per unit of purchased Voltage Support will be calculated in accordance with the formula in ISO Tariff Section 2.5.28.5.

Regulation Service

Regulation Obligation:

The amount of Regulation required will be calculated in accordance with Section 4.1 of the Ancillary Services Requirements Protocol (ASRP).

Regulation Rates:

The formulas for calculating the amount of and charges for Regulation Service are referenced in ISO Tariff Sections 2.5.20.1, 2.5.27, and 2.5.28.

The ISO will calculate the user rate for Regulation in each Zone for each Settlement Period in accordance with Section 2.5.28.1.

Spinning Reserve Service

Spinning Reserve Obligation:

The amount of Spinning Reserve required as a component of Operating Reserves is specified in Section 5.1 of the Ancillary Services Requirements Protocol (ASRP).

Spinning Reserve Rates:

The formulas for calculating the amount of and charges for Spinning Reserve Service are referenced in ISO Tariff Sections 2.5.27.2, 2.5.28.2.

The ISO will calculate the user rate for Spinning Reserve in each Zone for each Settlement Period in accordance with ISO Tariff Section 2.5.28.2.

Non-Spinning Reserve Service

Non-Spinning Reserve Obligation:

The amount of Non-Spinning Reserve required as a component of Operating Reserves is specified in Section 5.1 of the Ancillary Services Requirements Protocol (ASRP).

Non-Spinning Reserve Rates:

The formulas for calculating the amount of and charges for Non-Spinning Reserve Service are referenced in ISO Tariff Sections 2.5.27.3, 2.5.28.3.

The ISO will calculate the user rate for Non-Spinning Reserve in each Zone for each Settlement Period in accordance with ISO Tariff Section 2.5.28.3.

Replacement Reserves

The formulas for calculating the amount of and charges for Replacement Reserve Service are referenced in ISO Tariff Sections 2.5.27.4 and 2.5.28.4.

Black Start Capability

The user rate per unit of purchased Black Start capability for each Settlement Period will be calculated in accordance with ISO Tariff Section 2.5.28.6.

Imbalance Energy Charges

Rates for Imbalance Energy will be calculated in accordance with the formula in ISO Tariff Section 11.2.4.1.

Replacement Reserve Charge

The Replacement Reserve Charge will be calculated in accordance with ISO Tariff Sections 2.5.28.4 and 11.2.4.1.

Unaccounted for Energy

Rates for UFE will be calculated in accordance with ISO Tariff Section 11.2.4.1.

Transmission Losses Imbalance Charges

Transmission Losses for each hour will be calculated in accordance with ISO Tariff Sections 7.4.2.

Access Charges

The High Voltage Access Charge and Transition Charge is set forth in ISO Tariff Schedule 3 of Appendix F. The Low Voltage Access Charge of each Participating TO is set forth in that Participating TO's TO Tariff or comparable document.

Usage Charges

The amount payable by Scheduling Coordinators is determined in accordance with ISO Tariff Section 7.3.1.4.1. Usage Charges will be calculated in accordance with ISO Tariff Section 7.3.1.

Default Usage Charge

The Default Usage Charge will be used in accordance with ISO Tariff Section 7.3.1.3.

Grid Operations Charge for Intra-Zonal Congestion

Intra-Zonal Congestion during the initial period of operation will be managed in accordance with ISO Tariff Sections 7.2.6.1 and 7.2.6.2.

Wheeling Access Charges

The Wheeling Access Charge for transmission service is set forth in Section 7.1.4.1 of the ISO Tariff and Appendix II of the TO Tariffs.

Charge for Failure to Conform to Dispatch Instructions

The Charge for Failure to Conform to Dispatch Instructions will be determined in accordance with ISO Tariff Section 2.5.22.11.

Reliability Must-Run Charge

The Reliability Must-Run Charge will be determined in accordance with ISO Tariff Section 5.2.7.

FERC Annual Charge Recovery Rate

The FERC Annual Charge Recovery Rate will be determined in accordance with ISO Tariff Section 7.5.

ISO Tariff Appendix F

Schedule 3

High Voltage Access Charges

1. Objectives and Definitions

1.1 Objectives

(a) The Access Charge will remain utility-specific until a New Participating TO executes the Transmission Control Agreement, at which time the Access Charge will change as discussed below.

(b) The Access Charge is the charge assessed for using the ISO Controlled Grid. It consists of three components, the High Voltage Access Charge (HVAC), the Transition Charge and the Low Voltage Access Charge (LVAC).

(c) The HVAC ultimately will be based on one ISO Grid-wide rate. Initially, the HVAC will be based on TAC Areas, which will transition 10% per year to the ISO Grid-wide rate. In the first year after the Transition Date described in Section 4.2 of this Schedule 3, the HVAC will be a blend based on 10% ISO Grid-wide and 90% TAC Area.

(d) New High Voltage Facility additions and capital additions to Existing High Voltage Facilities will be immediately included in the ISO Grid-wide component of the HVAC. The Transmission Revenue Requirement for New High Voltage Facilities will not be included in the calculation of the Transition Charge.

(e) The LVAC will remain utility-specific and will be determined by each Participating TO. Each Participating TO will charge for and collect the LVAC.

(f) The cost-shift associated with transitioning from utility-specific rates to one ISO Grid-wide rate will be mitigated in accordance with the ISO Tariff, including this schedule.

1.2 Definitions

(a) Master Definition Supplement

Unless the context otherwise requires, any word or expression defined in the Master Definition Supplement shall have the same meaning where used in this Schedule 3.

(b) Special Definitions for this Appendix

When used in this Schedule 3 with initial capitalization, the following terms shall have the meanings specified below.

"High Voltage Utility-Specific Rate" means a Participating TO's High Voltage Transmission Revenue Requirement divided by such Participating TO's forecasted Gross Load.

"TAC Benefit" means the amount, if any, for each year by which the cost of Existing High Voltage Transmission Facilities associated with deliveries of Energy to Gross Loads in the PTO Service Territory is reduced by the implementation of the High Voltage Access Charge

described in Schedule 3 to Appendix F. The Tac Benefit of a New Participating TO shall not be less than zero.

"Transition Date" means the date defined in Section 4.2 of this Schedule.

2. Assessment of High Voltage Access Charge and Transition Charge.

All UDCs and MSS Operators in a PTO Service Territory serving Gross Loads directly connected to the transmission facilities or Distribution System of a UDC or MSS Operator in a PTO Service Territory shall pay to the ISO a charge for transmission service on the High Voltage Transmission Facilities included in the ISO Controlled Grid. The charge will be based on the High Voltage Access Charge applicable to the TAC Area in which the point of delivery is located and the applicable Transition Charge. A UDC or MSS Operator that is also a Participating TO shall pay, or receive payment of, if applicable, the difference between (i) the High Voltage Access Charge and Transition Charge applicable to its transactions as a UDC or MSS Operator; and (ii) the disbursement of High Voltage Access Charge revenues to which it is entitled pursuant to Section 7.1.3 of the ISO Tariff.

3. TAC Areas.

3.1 TAC Areas are based on the Control Areas in California prior to the ISO Operations Date. Three TAC Areas will be established based on the Original Participating TOs: (1) a Northern Area consisting of the PTO Service Territory of Pacific Gas and Electric Company and the PTO Service Territory of any entity listed in Section 3.3 or 3.5 of this Schedule; (2) an East Central Area consisting of the PTO Service Territory of Southern California Edison Company and the PTO Service Territory of any entity listed in Section 3.4, 3.5 or 3.6 (as indicated therein) of this Schedule 3; and (3) a Southern Area consisting of the PTO Service Territory of San Diego Gas & Electric Company. Participating TOs that are not in one of the above cited PTO Service Territories are addressed below.

3.2 If the Los Angeles Department of Water and Power joins the ISO and becomes a Participating TO, its PTO Service Territory will form a fourth TAC Area, the West Central Area.

3.3 If any of the following entities becomes a Participating TO, its PTO Service Territory will become part of the Northern Area: Sacramento Municipal Utility District, Western Area Power Administration - Sierra Nevada Region, the Department of Energy California Labs, Northern California Power Agency, City of Redding, Silicon Valley Power, City of Palo Alto, City and County of San Francisco, Alameda Bureau of Electricity, City of Biggs, City of Gridley, City of Healdsburg, City of Lodi, City of Lompoc Utility Department, Modesto Irrigation District, Turlock Irrigation District, Plumas County Water Agency, City of Roseville Electric Department, City of Shasta Lake, and City of Ukiah or any other entity owning or having contractual rights to High Voltage or Low Voltage Transmission Facilities in Pacific Gas and Electric Company's Control Area prior to the ISO Operations Date.

3.4 If any of the following entities becomes a Participating TO, its PTO Service Territory will become part of the East Central Area: City of Anaheim Public Utility Department, City of Riverside Public Utility Department, City of Azusa Light and Water, City of Banning Electric, City of Colton, City of Pasadena Water and Power Department, The Metropolitan Water District of Southern California and City of Vernon or any other entity owning or having contractual rights to High Voltage or Low Voltage Transmission Facilities in Southern California Edison Company's Control Area prior to the ISO Operations Date.

3.5 If the California Department of Water Resources becomes a Participating TO, its High Voltage Transmission Revenue Requirements associated with High Voltage Transmission Facilities in the Northern Area would become part of the High Voltage Transmission Revenue Requirement for the Northern Area while the remainder would be included in the East Central Area.

3.6 If the City of Burbank Public Service Department (Burbank) and/or the City of Glendale Public Service Department (Glendale) become Participating TOs after or at the same time as the Los Angeles Department of Water and Power becomes a Participating TO, then the PTO Service Territory of Burbank and/or Glendale would become part of the West Central Area. Otherwise, if Burbank or Glendale becomes a Participating TO, prior to Los Angeles, its PTO Service Territory will become part of the East Central Area. Once either Burbank or Glendale are part of the East Central Area, they will not move to the West Central Area if such area is established.

3.7 If the Imperial Irrigation District or an entity outside the State of California should apply to become a Participating TO, the ISO Governing Board will review the reasonableness of integrating the entity into one of the existing TAC Areas. If the entity cannot be integrated without the potential for significant cost shifts, the ISO Governing Board may establish a separate TAC Area.

4. Transition Date

4.1 New Participating TOs shall provide the ISO with a notice of intent to join and execute the Transmission Control Agreement by either January 1 or July 1 of any year and provide the ISO with an application within 15 days of such notice of intent.

4.2 The transition shall begin on either January 1 or July 1 after the date the first New Participating TO's execution of the Transmission Control Agreement takes effect (Transition Date). The Transition Date shall be the same for the Northern Area, East Central Area and the Southern Area. The Transition Date shall also be the same for the West Central Area, should it come into existence in accordance with Section 3.2 of this Schedule 3, unless the ISO provides additional information demonstrating the need for a deferral. The 10-year transition defined in Section 5.8 of Schedule 3 shall start from that date. If the West Central TAC Area is created after the Transition Date, the applicable High Voltage Access Charge shall transition to an ISO Grid-wide High Voltage Access Charge over the period remaining from the Transition Date, on the same schedule as the other TAC Areas.

4.3 **Application to Additional TAC Areas.** For any TAC Areas other than those specified in Section 4.2 of this Schedule 3, created after the Transition Date, including any TAC Area created as a result of the application of Section 3.7 of this Schedule 3, whether and over what period the applicable High Voltage Access Charge shall transition to an ISO Grid-wide charge shall be determined by the ISO Governing Board.

4.4 **Application to Wheeling Access Charges.** The transition described in this Section 4 shall also apply, on the same schedule, to High Voltage Wheeling Access Charges.

4.5 **Conversion of Existing Rights.** During the process by which a New Participating TO executes the Transmission Control Agreement, the ISO and potential New Participating TO that has an obligation to serve Load shall determine the amount of FTRs to be allocated to the New Participating TO for each Existing Right that the New Participating TO converts to Converted Rights. In making that determination, the ISO will consider the amount of contracted transmission capacity, the firmness of the contracted transmission capacity, and other characteristics of the contracted

transmission capacity to determine the amount of FTRs to be given to the New Participating TO in accordance with Section 9.4.3 of the ISO Tariff.

5. Determination of the Access Charge.

5.1 The Access Charge consists of a High Voltage Access Charge (HVAC) that is based on a TAC Area component and an ISO Grid-wide component, a Transmission Charge, and a Low Voltage Access Charge (LVAC) that is based on a utility-specific rate established by each Participating TO in accordance with its TO Tariff.

5.2 Each Participating TO will develop, in accordance with Section 6 of this Schedule 3, a High Voltage Transmission Revenue Requirement ($HVTRR_{PTO}$) consisting of a Transmission Revenue Requirement for Existing High Voltage Facility ($EHVTRR_{PTO}$) and a Transmission Revenue Requirement for New High Voltage Facility ($NHVTRR_{PTO}$). The $HVTRR_{PTO}$ includes the TRBA adjustment described in Section 6.1 of this Schedule 3.

5.3 The Gross Load amount in MWh shall be established by each Participating TO and filed at FERC with each Participating TO's Transmission Revenue Requirement (GL_{PTO}).

5.4 The HVAC applicable to each UDC or MSS Operator serving Gross Load in the PTO Service Territory, shall be based on a TAC Area component ($HVAC_A$) and an ISO Grid-wide component ($HVAC_I$).

$$HVAC = HVAC_A + HVAC_I$$

5.5 The Existing Transmission Revenue Requirement for the TAC Area component ($ETRR_A$) is the summation of each Participating TO's $EHVTRR_{PTO}$ in that TAC Area. The Gross Load in the TAC Area (GL_A) is the summation of each Participating TO's Gross Load in that TAC Area (GL_{PTO}). The TAC Area component will be based on the product of Existing Transmission Revenue Requirement for the TAC Area ($ETRR_A$) and the applicable annual transition percentage (%TA) in Section 5.8 of this Schedule 3, divided by the Gross Load in the TAC Area (GL_A).

$$ETRR_A = \Sigma\, EHVTRR_{PTO}$$

$$GL_A = \Sigma\, GL_{PTO}$$

$$HVAC_A = (ETRR_A * \%TA) / GL_A$$

5.6 The Existing Transmission Revenue Requirement for the ISO Grid-wide component ($ETRR_I$) will be the summation of all TAC Areas' $ETRR_A$ multiplied by the applicable annual transition percentage (%IGW) in Section 5.8 of this Schedule 3. The New Transmission Revenue Requirement (NTRR) is the summation of each Participating TO's $NHVTRR_{PTO}$. The ISO Grid-wide component will be based on the $ETRR_I$ plus the NTRR, divided by the summation of all Gross Loads in the TAC Areas (GL_A).

$$ETRR_I = \Sigma\, ETRR_A * \%IGW$$

$$HVAC_I = (ETRR_I + NTRR) / \Sigma\, GL_A$$

The foregoing formulas will be adjusted, as necessary to take account of new TAC Areas.

5.7 The Transition Charge shall be calculated separately for each Participating TO by dividing (i) the net difference between (1) the Participating TO's payment responsibility, if any, under Section 8.6 of the ISO Tariff and Section 7 of this Schedule 3; and (2) the amount, if any, payable to the Participating TO in accordance with Section 8.6 of the ISO Tariff and Section 7 of this Schedule 3; by (ii) the total of all forecasted Gross Load in the PTO Service Territory of the Participating TO, including the UDC and/or MSS Operator. If greater than zero, the Transition Charge shall be collected with the High Voltage Access Charge. If less than zero, the Transition Charge shall be credited with the High Voltage Access Charge. The amount of

each Participating TO's NHVTRR shall not be included in the Transition Charge calculation.

5.8 The High Voltage Access Charge shall transition over a 10-year period from TAC Area to ISO Grid-wide. The transition percentage to be used for each year will be based on the following:

Year	**TAC Area High Voltage (%TA)**	**ISO Grid-Wide High Voltage (%IGW)**
1	90%	10%
2	80%	20%
3	70%	30%
4	60%	40%
5	50%	50%
6	40%	60%
7	30%	70%
8	20%	80%
9	10%	90%
10	0%	100%

5.9 After the completion of the transition period described in Section 4 of this Schedule 3, the High Voltage Access Charge shall be equal to the sum of the High Voltage Transmission Revenue Requirements of all Participating TOs, divided by the sum of the Gross Loads of all Participating TOs.

6 High Voltage Transmission Revenue Requirement.

6.1 The High Voltage Transmission Revenue Requirement of a Participating TO will be determined consistent with ISO procedures posted on the ISO Home Page and shall be the sum of:

(a) the Participating TO's High Voltage Transmission Revenue Requirement (including costs related to Existing Contracts associated with transmission by others and deducting transmission revenues actually expected to be received by the Participating TO related to transmission for others in accordance with Existing Contracts, less the sum of the Standby Transmission Revenues); and

(b) the annual high voltage TRBA adjustment shall be based on the principal balance in the high voltage TRBA as of September 30, which shall be calculated as a dollar amount based on the projected Transmission Revenue Credits as adjusted for the true up of the prior year's difference between projected and actual credits. For a Participating TO that is not a UDC, MSS or a Scheduling Coordinator serving End-Use Customers and that does not have Gross Load in its TO Tariff in accordance with Appendix F, Schedule 3, Section 9, the Participating TO shall include any over- or under-recovery of its annual High Voltage Transmission Revenue Requirement in its high voltage TRBA. If the annual high voltage TRBA adjustment involves only a partial year of operations, the Participating TO's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Participating TO's High Voltage Transmission Revenue Requirement by the number of days the High Voltage Transmission Facilities were under the ISO's Operational Control divided by the number of days in the year.

7 Limitation

(a) During each year of the transition period described in this Schedule 3, the increase in the total payment responsibility applicable to Gross Loads in the PTO Service Territory of an Original Participating TO attributable to the total for the year of (i) the amount applicable for the Original Participating TO under Section 8.6 of the ISO Tariff; plus (ii) the amount applicable to the implementation of the High Voltage Access Charge shall not exceed the amount specified in paragraph (b) of this section. This limitation shall be calculated individually for each Original Participating TO, provided that, if the net effect of clauses (i) and (ii) of this paragraph is positive for one or more Original Participating TOs for any year, the combined net effect shall be allocated among all Original Participating TOs in proportion to the amounts specified in paragraph (b) of this section. This limitation shall be applied by the ISO's calculation annually of amounts payable by New Participating TOs to Original Participating TOs such that the combined effect of clauses (i) and (ii) of this paragraph, and the payments received by each Original Participating TO shall not exceed the amounts specified in paragraph (b) of this section. The amount receivable by the Original Participating TO from the New Participating TOs to implement the limitation in paragraph (b) of this section, shall be credited through the Transition Charge established pursuant to Section 5.7 of this Schedule 3.

Payment responsibility under this section, if any, shall be allocated among New Participating TOs in proportion to their TAC Benefits.

(b) The maximum annual amounts for Original Participating TO shall be as follows:

(i) For Pacific Gas and Electric Company and Southern California Edison Company, the maximum annual amount shall be thirty-two million dollars ($32,000,000.00) each; and

(ii) For San Diego Gas & Electric Company, the maximum annual amount shall be eight million dollars ($8,000,000.00).

8. Updates to High Voltage Access Charges.

8.1 High Voltage Access Charges and High Voltage Wheeling Access Charges shall be adjusted: (1) on January 1 and July 1 of each year when necessary to reflect the addition of any New Participating TO and (2) on the date FERC makes effective a change to the High Voltage Transmission Revenue Requirements of any Participating TO. Using the High Voltage Transmission Revenue Requirement accepted or authorized by FERC, consistent with Section 9 of this Schedule 3, for each Participating TO, the ISO will recalculate on a monthly basis the High Voltage Access Charge and Transition Charge applicable during such period. Revisions to the Transmission Revenue Balancing Account adjustment shall be made effective annually on January 1 based on the principal balance in the TRBA as of September 30 of the prior year and a forecast of Transmission Revenue Credits for the next year.

8.2 For service provided by a Participating TO prior to the Transition Date, no refund ordered by FERC or amount accrued to that Participating TO's Transmission Revenue Balancing Account related to such service shall be reflected in the High Voltage Access Charge, Low Voltage Access Charge, the High Voltage Transmission Revenue Requirement, or the Low Voltage Transmission Revenue Requirement of a Participating TO. For service provided by a Participating TO following the Transition Date, any refund associated with a Participating TO's Transmission Revenue Requirement that has been accepted by FERC, subject to refund, shall be provided as ordered by FERC. Such refund shall be invoiced separately from the Market Invoice.

8.3 If the Participating TO withdraws one or more of its transmission facilities from the ISO Operational Control in accordance with Section 3.4 of the Transmission Control Agreement, then the ISO will no longer collect the TRR for that transmission facility through the ISO's Access Charge effective upon the date the transmission facility is no longer under the Operational Control of the ISO. The withdrawing Participating TO shall be obligated to provide the ISO will all necessary information to implement the withdrawal of the Participating TO's transmission facilities and to make any necessary filings at FERC to revise its TRR. The ISO shall revise its transmission Access Charge to reflect the withdrawal of one or more transmission facilities from ISO Operational Control.

9. Approval of Updated High Voltage Revenue Requirements

9.1 Participating TOs will make the appropriate filings at FERC to establish their Transmission Revenue Requirements for their Low Voltage Access Charges and the applicable High Voltage Access Charges, and to obtain approval of any changes thereto. All such filings with the FERC will include a separate appendix that states the HVTRR,

LVTRR (if applicable) and the appropriate Gross Load data and other information required by the FERC to support the Access Charges. The Participating TO will provide a copy of its filing to the ISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

9.2 Federal power marketing agencies whose transmission facilities are under ISO Operational Control shall develop their High Voltage Transmission Revenue Requirements pursuant to applicable federal laws and regulations, including filing with FERC. All such filings with FERC will include a separate appendix that states the HVTRR, LVTRR (if applicable) and the appropriate Gross Load data and other information required by the FERC to support the Access Charges. The procedures for public participation in a federal power marketing agency's ratemaking process shall be posted on the federal power marketing agency's website. The federal power marketing agency shall also post on the website the Federal Register Notices and FERC orders for rate making processes that impact the federal power marketing agency's High Voltage Transmission Revenue Requirement. The Participating TO will provide a copy of its filing to the ISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

10. Disbursement of High Voltage Access Charge and Transition Charge Revenues.

10.1 High Voltage Access Charge and Transition Charge revenues shall be calculated for disbursement to each Participating TO on a monthly basis as follows:

(a) the amount determined in accordance with Section 7.1.2 of the ISO Tariff ("Billed HVAC/TC");

(b)

(i) for a Participating TO that is a UDC or MSS Operator and has Gross Load in its TO Tariff in accordance with Appendix F, Schedule 3, Section 9, then calculate the amount each UDC or MSS Operator would have paid and the Participating TO would have received by multiplying the High Voltage Utility-Specific Rates for the Participating TO whose High Voltage Facilities served such UDC and MSS Operator

times the actual Gross Load of such UDCs and MSS Operators ("Utility-specific HVAC"); or

(ii) for a Participating TO that is not a UDC or MSS Operator and that does not have Gross Load in its TO Tariff in accordance with Appendix F, Schedule 3, Section 9, then calculate the Participating TO's portion of the total Billed HVAC/TC in subsection (a) based on the ratio of the Participating TO's High Voltage Transmission Revenue Requirement to the sum of all Participating TOs' High Voltage Revenue Requirements.

(c) if the total Billed HVAC/TC in subsection (a) received by the ISO less the total dollar amounts calculated in Utility-specific HVAC in subsection (b)(i) and subsection (b)(ii) is different from zero, the ISO shall allocate the positive or negative difference among those Participating TOs that are subject to the calculations in subsection (b)(i) based on the ratio of each Participating TO's High Voltage Transmission Revenue Requirement to the sum of all of those Participating TOs' High Voltage Transmission Revenue Requirements that are subject to the calculations in subsection (b)(i). This monthly distribution amount is the "HVAC Revenue Adjustment";

(d) the sum of the HVAC revenue share determined in subsection (b) and the HVAC Revenue Adjustment in subsection (c) will be the monthly disbursement to the Participating TO.

10.2 If the same entity is both a Participating TO and a UDC or MSS Operator, then the monthly High Voltage Access Charge and Transition Charge amount billed by the ISO will be the charges payable by the UDC or MSS Operator in accordance with Section 7.1.2 of the ISO Tariff less the disbursement determined in accordance with Section 10.1(d). If this difference is negative, that amount will be paid by the ISO to the Participating TO.

11 Determination of Transmission Revenue Requirement Allocation Between High Voltage and Low Voltage Transmission Facilities.

11.1 Each Participating TO shall allocate its Transmission Revenue Requirement between the High Voltage Transmission Revneue Requirement and Low Voltage Transmission Revenue Requirement based on the Procedure for Division of Certain Costs Between the High and Low Voltage Transmission Access Charges contained in Section 12 of this Schedule.

12 Procedure for Division of Certain Costs Between the High and Low Voltage Transmission Access Charges.

12.1 Division of Costs:

(a) Substations

Costs for substations and substation equipment, including transformers:

(i) If the Participating TO has substation TRR information by facility and voltage, then the TRR for facilities and equipment at or above 200 kV should be allocated to the HVTRR and the TRR for facilities and equipment below 200 kV should be allocated to the LVTRR;

(ii) If the Participating TO has substation TRR information by facility but not by voltage, then the TRR for facilities and equipment should be allocated to the HVTRR and to the LVTRR based on the ratio of gross substation investment allocated to HVTRR to gross substation investment allocated to LVTRR pursuant to Section 12.1(a)(i); or

(iii) If the Participating TO does not have substation TRR information by facility or voltage, then the TRR for facilities and equipment should be allocated to the HVTRR and to the LVTRR based on the Participating TO's transmission system-wide gross plant ratio. The system-wide gross plant ratio is determined once the costs that can be split between High Voltage and Low Voltage for all facilities has been developed in accordance with Sections 12.1(a) through (c), then the resulting cost ratio between High Voltage and Low Voltage shall be used as the system-wide gross plant ratio.

(iv) Costs of transformers that step down from high voltage (200 kV or above) to low voltage, to the extent the Participating TO does not have the revenue requirement information available on a voltage basis, should be allocated consistent with the procedures for substations addressed above.

(b) Transmission Towers and Land with Circuits on Multiple Voltages

For transmission towers that have both High Voltage and Low Voltage facilities on the same tower, the cost of these assets should be allocated two-thirds to the HVTRR and one-third to the LVTRR. If the transmission tower has only High Voltage facilities, then the costs of these assets should be allocated entirely to the HVTRR. If the transmission tower has only Low Voltage facilities, then the TRR of these assets should be allocated entirely to the LVTRR. Provided that the Participating TO does not have land cost information available on a voltage

basis, in which case the costs should be allocated based on the bright-line of the voltage levels, the costs for land used for transmission rights-of-way for towers that have both High Voltage and Low Voltage wires should be allocated two-thirds to the HVTRR component and one-third to the LVTRR.

(c) Operation and Maintenance, Transmission Wages & Salaries, Taxes, Depreciation and Amortization, and Capital Costs

If the Participating TO can delineate costs for transmission operations and maintenance (O&M), transmission wages and salaries, taxes, depreciation and amortization, or capital costs on a voltage basis, the costs shall be applied on a bright-line voltage basis. If the costs for O&M, transmission wages and salaries, taxes, depreciation and amortization, or capital costs, are not available on voltage levels, the allocation to the HVTRR and the LVTRR should be based on the Participating TO's system-wide gross plant ratio defined in Section 12.1(a).

(d) Existing Transmission Contracts

If the take-out point for the Existing Contract is a High Voltage Transmission Facility, the Existing Contract revenue will be credited to the HVTRR of the Participating TO receiving such revenue. Similarly, the Participating TO that is paying charges under such an Existing Contract may include the costs in its HVTRR. If the take-out point for the Existing Contract is a Low Voltage Transmission Facility, the Existing Contract revenue will be credited to the HVTRR and the LVTRR of the receiving Participating TO based on the ratio of the Participating TO's HVTRR to its LVTRR, prior to any adjustments for such revenues. The Participating TO that is paying the charges under the Existing Contract will include the costs in its HVTRR and LVTRR in the same ratio as the revenues are recognized by the Participating TO receiving the payments.

(e) Division of the TRBAA between HVTRR and LVTRR

(i) Wheeling revenues associated with transactions exiting the ISO Controlled Grid at High Voltage Scheduling Points or Take-Out Points shall be reflected as High Voltage components;

(ii) Wheeling revenues associated with transactions exiting the ISO Controlled Grid at Low Voltage Scheduling Points or Take-Out Points shall be attributed between High Voltage and Low Voltage TRBAA components based on the High Voltage and Low Voltage Wheeling Access Charge rates assessed to such transactions by the ISO and/or the Participating TO;

(iii) FTR revenues shall be assigned to High Voltage or Low Voltage components based on the voltage of the path related to the FTR;

(iv) Usage Charge revenues shall be allocated between High Voltage and Low Voltage components on a gross plant basis; and

(v) Other Transmission Revenue Credits shall be allocated between High Voltage and Low Voltage components on a gross plant basis.

ISO Tariff Appendix F

Schedule 4

Participating Intermittent Resources Forecasting Fee

A charge up to $.10 per MWh shall be assessed on the metered Energy from Participating Intermittent Resources. The amount of the charge shall be specified in the ISO Protocols.