INDEX

4.5.1.1 Procedure to become a Scheduling Coordinator.

4.5.1.1.1 Scheduling Coordinator Applicant makes a Request.

To become a Scheduling Coordinator, a Scheduling Coordinator Applicant must submit a written application to the ISO by mail, fax, e-mail or in person. A Scheduling Coordinator Applicant may retrieve the application and necessary information from the ISO Home Page.

4.5.1.1.2 ISO Information.

The ISO will provide the following information, in its most current form, on the ISO Home Page. Upon a request by a Scheduling Coordinator Applicant, the ISO will send the following information by mail:

(a) the Scheduling Coordinator Application Form (including the ISO Application File Template, which is Appendix T);

(b) the ISO Tariff and ISO Protocols;

(c) Interim Black Start Agreement;

(d) historical ISO charges (Note: prior to January 2, 1998, estimated ISO charges) including, but not limited to, charges for purchased Ancillary Services, ISO Grid Management Charge, ISO Grid Operations Charge, Imbalance Energy market charges, and Usage Charges to assist the Scheduling Coordinator Applicant in determining the Financial Security Amount the Scheduling Coordinator Applicant must provide; and

(e) a completed credit application for Scheduling Coordinator Applicants applying for Unsecured Credit Limits or Financial Security to be provided pursuant to Section 12.1.2.

4.5.1.1.3 Duplicate Information.

If two or more Scheduling Coordinators apply simultaneously to register with the ISO for a single meter or Meter Point for an ISO Metered Entity or if an Scheduling Coordinator applies to register with the ISO for a meter or Meter Point for an ISO Metered Entity for which an Scheduling Coordinator has already

registered, the ISO will return the application with an explanation that only one Scheduling Coordinator may register with the ISO for the meter or Meter Point in question and that an Scheduling Coordinator has already registered or that more than one Scheduling Coordinator is attempting to register for that meter or Meter Point. The ISO will send the Scheduling Coordinator Applicant the name and address of the applicable Scheduling Coordinator or Scheduling Coordinator Applicant.

4.5.1.1.4 Scheduling Coordinator Applicant returns Application.

At least 60 days before the proposed commencement of service, the Scheduling Coordinator Applicant must return a completed application form with the non-refundable application fee set by the ISO Governing Board to cover the application processing costs, site visit and the costs of furnishing the ISO Tariffs.

4.5.1.1.5 Notice of Receipt.

Within 3 Business Days of receiving the application, the ISO will send a written notification to the Scheduling Coordinator Applicant that it has received the application and the non-refundable fee.

4.5.1.1.6 ISO Review of Application.

Within 14 days after receiving an application, the ISO will notify the Scheduling Coordinator Applicant whether the Scheduling Coordinator Applicant has submitted all necessary information as set forth in ISO Tariff Section 4.5.1, and the ISO Application File Template requirements.

4.5.1.1.6.1 Information Requirements.

The Scheduling Coordinator Applicant must submit with its application:

(a) the proposed date for commencement of service, which may not be less than 60 days after the date the application, was filed, unless waived by the ISO;

(b) financial and security information as set forth in ISO Tariff Section 12.1; and

(c) the prescribed non-refundable application fee.

4.5.1.1.9 Scheduling Coordinator Applicant's Response.

4.5.1.1.9.1 Scheduling Coordinator Applicant's Acceptance.

If the ISO accepts the application, the Scheduling Coordinator Applicant must return an executed Scheduling Coordinator Agreement, Meter Service Agreements, Interim Black Start Agreements, completed credit application provided pursuant to Section 12.1.1, and Financial Security provided pursuant to Section 12.1.2, as applicable.

4.5.1.1.9.2 Scheduling Coordinator Applicant's Rejection.

4.5.1.1.9.2.1 Resubmittal.

If an application is rejected, the Scheduling Coordinator Applicant may resubmit its application at any time. An additional application fee will not be required for the second application submitted within 6 months after a rejection.

4.5.1.1.9.2.2 Appeal.

The Scheduling Coordinator Applicant may also appeal against the rejection of an application by the ISO. An appeal must be submitted within 28 days following the rejection of its application.

4.5.1.1.10 Post Application Procedures Prior To Final Certification.

4.5.1.1.10.1 Scheduling Coordinator's Administrative, Financial and Technical Requirements.

The ISO will not certify that an Scheduling Coordinator Applicant has become a Scheduling Coordinator until the Scheduling Coordinator Applicant has:

(a) provided the technical/operational information required to complete the ISO Application File Template, and to comply with ISO Tariff Section 10.3;

(b) executed software licensing agreement for the software used in conducting business with the ISO in a form approved by the ISO, if applicable;

(c) bought and installed any required software for functional interface in order to Validate, Estimate and Edit meter values (VEE).

(d) purchased the requisite Value Area Network (VAN) service in order to support Electronic Data Interchange (EDI) requirements;

(e) provided its bank account information and arranged for Fed-Wire System transfers as defined in Tariff Appendix A;

(f) submitted a timetable for completion of its operational facilities, in order to coordinate site visits by ISO staff to ensure compliance with the ISO Tariff Section 4.5.4.1; and

(g) bought and installed a computer link account in order to communicate with the ISO.

4.5.1.1.11 Final Certification of Scheduling Coordinator Applicant.

The Scheduling Coordinator Applicant will become a Scheduling Coordinator when:

(a) its application has been accepted;

(b) it has entered into an Scheduling Coordinator Agreement, Meter Service Agreements and Interim Black Start Agreements, if applicable, with the ISO;

(c) the Scheduling Coordinator Applicant has met the financial requirements of ISO Tariff Section 12.1; and

(d) the Scheduling Coordinator Applicant has fulfilled all technical/operational requirements of ISO Tariff Section 4.5.4.1, Section 4.5.1.1.10.1, and the ISO Application File Template.

The ISO will not certify a Scheduling Coordinator Applicant as a Scheduling Coordinator until the Scheduling Coordinator Applicant has completed all the above referenced requirements to the ISO's satisfaction, at least 14 days before the commencement of service.

4.5.1.2 Scheduling Coordinator's Ongoing Obligations After Certification.

4.5.1.2.1 Scheduling Coordinator's Obligation to Report Changes.

4.5.1.2.1.1 Obligation to Report a Change in Filed Information.

Each Scheduling Coordinator has an ongoing obligation to inform the ISO of any changes to any of the information submitted by it to the ISO as part of the application process, including any changes to the additional information requested by the ISO and including but not limited to changes in its credit ratings. Appendix T sets forth the procedures for changing the Scheduling Coordinator's information and timing of notifying the ISO of such changes.

4.5.1.2.1.2 Obligation to Report a Change in Credit Ratings or Material Change in Financial Condition.

The SC has an ongoing obligation to inform the ISO within 5 Business Days of any change to its credit ratings or any Material Change in Financial Condition.

4.5.1.2.2 ISO's Response for Failure to Inform.

4.5.1.2.2.1 Failure to Promptly Report a Material Change.

If a Scheduling Coordinator fails to inform the ISO of a material change in its information provided to the ISO, which may affect the reliability or safety of the ISO Controlled Grid, or the financial security of the ISO, the ISO may suspend or terminate the Scheduling Coordinator's rights under the ISO Tariff in accordance with the terms of ISO Tariff Sections 12.3 and 4.5.1 respectively. If the ISO intends to terminate the Scheduling Coordinator's rights it shall file a Notice of Termination with FERC. Such termination shall be effective upon acceptance by FERC of a Notice of Termination.

4.5.2 Eligible Customers Represented by Scheduling Coordinators.

Each Scheduling Coordinator shall within ten (10) days of a request by the ISO provide the ISO with a list of the Eligible Customers which it represents at the date of the request.

4.5.3 Responsibilities of a Scheduling Coordinator.

Each Scheduling Coordinator shall be responsible for:

4.5.3.1 Obligation to Pay. Paying the ISO's charges in accordance with this ISO Tariff;

4.5.3.2 Submit Schedules. Submitting Schedules for Energy in the Day-Ahead Market and Hour-Ahead Market in relation to Market Participants for which it serves as Scheduling Coordinator, Scheduling Coordinators shall provide the ISO with intertie Interconnection schedules prepared in accordance with all NERC, WECC and ISO requirements;

4.5.3.3 Modifications in Demand and Supply. Coordinating and allocating modifications in scheduled Demand and exports and scheduled Generation and imports at the direction of the ISO in accordance with this ISO Tariff;

4.5.3.3A Trades between Scheduling Coordinators. Billing and settling an Inter-Scheduling Coordinator Energy or Ancillary Service Trade shall be done in accordance with the agreements between the parties to the trade. The parties to an Inter-Scheduling Coordinator Energy or Ancillary Service Trade shall notify the ISO, in accordance with the ISO Protocols, of the Zone in which the transaction is deemed to occur, which, for Inter-Scheduling Coordinator Energy Trades, shall be used for the purpose of identifying which Scheduling Coordinator will be responsible for payment of applicable Usage Charges;

4.5.3.4 Scheduling Deliveries. Including in its Schedules to be submitted to the ISO under this ISO Tariff, the Demand, Generation and Transmission Losses necessary to give effect to trades with other Scheduling Coordinators;

4.5.3.5 Tracking and Settling Trades. Tracking and settling all intermediate trades among the entities for which it serves as Scheduling Coordinator;

4.5.3.6 Ancillary Services. Providing Ancillary Services in accordance with Section 8;

4.5.3.7 Annual and Weekly Forecasts. Submitting to the ISO the forecasted weekly peak Demand on the ISO Controlled Grid and the forecasted Generation capacity. The forecasts shall cover a period of twelve (12) months on a rolling basis;

4.5.3.8 ISO Protocols. Complying with all ISO Protocols and ensuring compliance by each of the Market Participants which it represents with all applicable provisions of the ISO Protocols;

4.5.3.9 Interruptible Imports. Identifying any Interruptible Imports included in its Schedules;

4.5.3.10 Participating Intermittent Resources. Submitting Schedules consistent with the ISO Protocols; and

4.5.3.11 Compliance with Environmental Constraints, Operating Permits and Applicable Law. Submitting Ancillary Services bids, Adjustment Bids and Supplemental Energy bids so that any service provided in accordance with such bids does not violate environmental constraints, operating permits or applicable law. All submitted bids must reflect resource limitations and other constraints as such are required to be reported to the ISO Control Center.

4.5.4 Operations of a Scheduling Coordinator.

4.5.4.1 Maintain Twenty-four (24) Hour Scheduling Centers.

Each Scheduling Coordinator shall operate and maintain a twenty-four (24) hour, seven (7) days per week, scheduling center. Each Scheduling Coordinator shall designate a senior member of staff as its scheduling center manager who shall be responsible for operational communications with the ISO and who shall have sufficient authority to commit and bind the Scheduling Coordinator.

4.5.4.2 Submitting Balanced Schedules.

A Scheduling Coordinator shall submit to the ISO only Balanced Schedules in the Day-Ahead Market and the Hour-Ahead Market. A Schedule shall be treated as a Balanced Schedule when aggregate Generation, Inter-Scheduling Coordinator Energy Trades (whether purchases or sales), and imports or exports to or from external Control Areas adjusted for Transmission Losses as appropriate, equals aggregate forecast Demand with respect to all entities for which the Scheduling Coordinator schedules in each Zone. If a Scheduling Coordinator submits a Schedule that is not a Balanced Schedule, the ISO shall reject that Schedule provided that Scheduling Coordinators shall have an opportunity to validate their Schedules prior to the deadline for submission to the ISO by requesting such validation prior to the applicable deadline. On an interim basis, the ISO may assist Scheduling Coordinators in matching Inter-Scheduling Coordinator Energy Trades.

4.5.4.2.1 Submission of Schedules Sufficient to Meet Forecasted Demand

4.5.4.2.1.1 Each Scheduling Coordinator shall submit to the ISO, for each hour of each Trading Day, a Day-Ahead Schedule that includes at least ninety-five percent (95%) of that Scheduling Coordinator's forecast Demand for each hour, for each UDC Service Area, with respect to all entities for which the Scheduling Coordinator schedules in the applicable UDC Service Areas. The requirements of this section do not apply to the portion of a Scheduling Coordinator's Demand associated with Station Power.

4.5.4.3 Dynamic Scheduling.

Scheduling Coordinators may dynamically schedule imports of Energy, Supplemental Energy, and Ancillary Services (other than Regulation) for which associated Energy is delivered dynamically from System Resources located outside of the ISO Control Area, provided that (a) such dynamic scheduling is technically feasible and consistent with all applicable NERC and WECC criteria and policies, (b) all operating, technical, and business requirements for dynamic scheduling functionality, as posted in standards on the ISO Home Page, are satisfied, (c) the Scheduling Coordinator for the dynamically scheduled System Resource executes an agreement with the ISO for the operation of dynamic scheduling functionality, and (d) all affected host and intermediary Control Areas each execute with the ISO an Interconnected Control Area Operating Agreement ("ICAOA") or special operating agreement related to the operation of dynamic functionality. See the forms of agreement in Attachment A to Appendix X.

4.5.4.4 Termination of Service Agreement.

(a) A Scheduling Coordinator's Scheduling Coordinator Agreement may be terminated by the ISO on written notice to the Scheduling Coordinator:

(i) if the Scheduling Coordinator no longer meets the requirements for eligibility set out in Section 4.5 and fails to remedy the default within a period of seven (7) days after the ISO has given written notice of the default;

(ii) if the Scheduling Coordinator fails to pay any sum under this ISO Tariff and fails to remedy the default within a period of seven (7) days after the ISO has given written notice of the default; or

Operator provides documentation to the ISO by November 1 of any year demonstrating that the MSS Operator has secured generating capacity for the following calendar year at least equal to one hundred and fifteen percent (115%), on an annual basis, of the peak Demand responsibility of the MSS Operator, the ISO shall grant the exemption. Eligible generating capacity for such a demonstration may include on-demand rights to Energy, peaking resources, and Demand reduction programs. The peak Demand responsibility of the MSS Operator shall be equal to the annual peak Demand Forecast of the MSS Load plus any firm power sales by the MSS Operator, less interruptible Loads, and less any firm power purchases. Firm power for the purposes of this Section 4.9.16.2 shall be Energy that is intended to be available to the purchaser without being subject to interruption or curtailment by the supplier except for Uncontrollable Forces or emergency. To the extent that the MSS Operator demonstrates that it has secured generating capacity in accordance with this Section 4.9.16.2., the Scheduling Coordinator for the MSS Operator shall not be obligated to bear any share of the ISO's costs for any summer Demand reduction program or for any summer reliability Generation procurement program pursuant to ISO Tariff Section 42.1.8 for the calendar year for which the demonstration is made.

4.9.16.3 If the ISO is compensating Generating Units for Emissions Costs, Start-Up Fuel Costs and Minimum Load Costs, and if MSS Operator charges the ISO for the Emissions Costs, Start-Up Fuel Costs and Minimum Load Costs, of the Generating Units serving the Load of the MSS, then the Scheduling Coordinator for the MSS shall bear its proportionate share of the total amount of those costs incurred by the ISO based on the MSS gross metered Demand and exports and the Generating Units shall be made available to the ISO through the submittal of Supplemental Energy bids. If the MSS

Operator chooses not to charge the ISO for the Emissions Costs, Start-Up Fuel Costs and Minimum Load Costs of the Generating Units serving the Load of the MSS, then the Scheduling Coordinator for the MSS shall bear its proportionate share of the total amount of those costs incurred by the ISO based on the MSS's net metered Demand and exports. The MSS Operator shall make the election whether to charge the ISO for these costs on an annual basis on November 1 for the following calendar year.

4.9.16.4 The Scheduling Coordinator for the MSS shall be responsible for Transmission Losses, in accordance with the ISO Tariff, only within the MSS, at any points of interconnection between the MSS

and the ISO Controlled Grid, and for the delivery of Energy to the MSS or from the MSS, provided the MSS Operator fulfills its obligation to provide for Transmission Losses on the transmission facilities forming part of the MSS. A Generation Meter Multiplier shall be assigned to the Generating Units on the MSS at the Points of Interconnection for use of the ISO Controlled Grid. That GMM shall be 1.0 for all Generating Units within the MSS that are located at or behind a Point of Interconnection, to the extent that the Load at the Point of Interconnection for that portion of the MSS exceeds the amount of Generation produced by the Generating Units connected to that portion of the MSS, except that a GMM shall be calculated by the ISO for Energy produced pursuant to a Dispatch instruction from the ISO.

4.9.16.5 If the MSS Operator has elected to follow its Load in accordance with Section 4.9.9, then the MSS is not eligible to receive bid cost recovery as provided for in Section 11.2.4.1.1.1 and the Scheduling Coordinator for the MSS shall be allocated costs associated with bid cost recovery on a net Metered Demand basis. If the MSS Operator has elected to not follow its Load in accordance with Section 4.9.9, then the MSS is eligible to receive bid cost recovery as provided for in Section 11.2.4.1.1.1, if applicable, subject to resource-specific performance review, and the Scheduling Coordinator for the MSS shall be allocated costs associated with bid cost recovery on a gross metered Demand basis.

5 RELATIONSHIP BETWEEN ISO AND SUDCS.

5.1 General Nature of Relationship Between ISO and SUDCs.

5.1.1 The ISO shall not be obliged to accept Schedules, Adjustment Bids or bids for Ancillary Services which would require Energy to be transmitted to or from the Distribution System of a SUDC directly connected to the ISO Controlled Grid unless the relevant SUDC has entered into a SUDC Operating Agreement. The SUDC Operating Agreement shall require SUDCs to comply with the applicable provisions of this Section 5 and any other expressly applicable Sections of this ISO Tariff, as they may be amended from time to time. The ISO shall maintain a pro forma SUDC Operating Agreement available for SUDCs to enter into with the ISO.

5.1.2 The ISO shall operate the ISO Control Area and the ISO Controlled Grid and each SUDC shall operate its Distribution System at all times in accordance with Good Utility Practice and in a manner

6.5 Information to be Provided By Connected Entities to the ISO.

6.5.1 Each Participating TO and Connected Entity shall provide to the ISO:

6.5.1.1 A single and an alternative telephone number and a single and an alternative facsimile number by which the ISO may contact 24 hours a day a representative of the Participating TO or Connected Entity in, or in relation to, a System Emergency;

6.5.1.2 The names or titles of the Participating TO's or Connected Entity's representatives who may be contacted at such telephone and facsimile numbers.

6.5.2 Each representative specified pursuant to Section 6.5.1 shall be a person having appropriate experience, qualification, authority, responsibility and accountability within the Participating TO or the Connected Entity to act as the primary contact for the ISO in the event of a System Emergency.

6.5.3 The details required under this Section 6.5 shall at all times be maintained up to date and the Participating TO and the Connected Entity shall notify the ISO of any changes promptly and as far in advance as possible.

6.6 Failure or Corruption of the WEnet.

The ISO shall, in consultation with Scheduling Coordinators, make provision for procedures to be implemented in the event of a total or partial failure of WEnet or the material corruption of data on WEnet and include these procedures in the ISO Protocols. The ISO shall ensure that such alternative communications systems are tested periodically.

6.7 Confidentiality.

All information posted on WEnet shall be subject to the confidentiality obligations contained in Section 20 of this ISO Tariff.

6.8 Standards of Conduct.

The ISO and all Market Participants shall comply with their obligations, to the extent applicable, under the standards of conduct set out in 18 C.F.R. §37.

6.9 ISO Postings.

6.9.1 Information to be Provided by the ISO to all Scheduling Coordinators. By 6:00 p.m. two days prior to a Trading Day, the ISO shall publish on WEnet information, including the following to all Scheduling Coordinators for each Settlement Period of the Trading Day:

6.9.1.1 Scheduled Line Outages. Scheduled transmission line Outages;

6.9.1.2 Forecast Loop-Flow. Forecast Loop Flow over ISO Inter-Zonal Interfaces and Scheduling Points;

6.9.1.3 Advisory Demand Forecasts. Advisory Demand Forecasts by location;

6.9.1.4 Updated Transmission Loss Factors. Updated Generation Meter Multipliers reflecting Transmission Losses to be supplied by each Generating Unit and by each import into the ISO Control Area;

6.9.1.5 Ancillary Services. Expected Ancillary Services requirement by reference to Zones for each of the reserve Ancillary Services.

6.9.2 Public Dissemination of Information: Day-Ahead.

By 3:00 p.m. of the day preceding the Trading Day, the ISO shall make available to all Market Participants the following information on the scheduling of Ancillary Services: Ancillary Service	Quantity Units	Period	Clearing Prices
Regulation/AGC	MW	Hourly	$/MW
Spinning Reserve	MW	Hourly	$/MW

(c) all 230 kV and lower voltage transmission lines and associated station equipment identified in the ISO Register as that portion of the ISO Controlled Grid located in the PG&E PTO Service Territory.

7.1.5 Backup ISO Control Center.

The Backup ISO Control Center shall have Operational Control over all 230 kV and lower voltage transmission lines and associated station equipment identified in the ISO Register as that portion of the ISO Controlled Grid located in the SCE and SDGE PTO Service Territories.

7.2 Operating Reliability Criteria.

7.2.1 Reliability Coordinator.

The ISO shall be the WECC reliability coordinator for the ISO Controlled Grid. As Reliability Coordinator, the ISO, in conjunction with the other WECC Reliability Coordinators, will be responsible for the stable and reliable operation of the Western Interconnection in accordance with the WECC Regional Security Plan.

7.2.1.1 Reliability Coordinator.

As Reliability Coordinator, the ISO may direct activities as appropriate to curtail Schedules, Dispatch Generation or impose transfer limitations as necessary to relieve grid Congestion, mitigate potential overloads or eliminate operation outside of existing Nomogram criteria.

7.2.1.2 Authority of WECC Reliability Coordinators.

(a) The Reliability Coordinator has the final authority to direct operations before, during and after problems or disturbances that have regional impacts. The WECC Security Monitoring plans include collaboration with sub-regional Reliability Coordinators and Control Area operators to determine actions for anticipated problems. If there is insufficient time, or mutual concurrence is not reached, the Reliability Coordinator is authorized to direct actions and the control area operators must comply.

(b) In the event of any situation occurring which is outside those problems already identified in the list of known problems, the Reliability Coordinator shall have the responsibility and authority to implement whatever measures are necessary to maintain System Reliability. Those actions include but are not

limited to; interchange curtailment, generation Dispatch adjustment (real power, reactive power and voltage), transmission configuration adjustments, special protection activation, load curtailment and any other action deemed necessary to maintain System Reliability.

(c) The Reliability Coordinator shall also have the responsibility and authority to take action in its sub-region for problems in another sub-region that it may help resolve. This must be accomplished at the request of and in coordination with the Reliability Coordinators of the other sub-regions.

7.2.2 [Not used]

7.2.2.1 The ISO shall exercise Operational Control over the ISO Controlled Grid to meet planning and Operating Reserve criteria no less stringent than those established by WECC and NERC as those standards may be modified from time to time, and Local Reliability Criteria that are in existence on the ISO Operations Date and have been submitted to the ISO by each Participating TO pursuant to Section 2.2.1(v) of the TCA. All Market Participants and the ISO shall comply with the ISO Reliability Criteria, standards, and procedures.

7.2.2.2 The ISO Governing Board may establish planning guidelines more stringent than those established by NERC and WECC as needed for the secure and reliable operation of the ISO Controlled Grid. The ISO may revise the Local Reliability Criteria subject to and in accordance with section 5 of the TCA.

7.2.2.3 Standards to be Observed.

The ISO shall exercise Operational Control over the ISO Controlled Grid in compliance with all Applicable Reliability Criteria.

7.2.2.3.1 Applicable Reliability Criteria.

Applicable Reliability Criteria are defined as the standards established by NERC, WECC and Local Reliability Criteria and include the requirements of the Nuclear Regulatory Commission (NRC).

7.2.2.3.2 WECC Criteria (Standards).

(a) Western Interconnection.

8.3.2 Procurement Not Limited to ISO Control Area.

The ISO will procure Spinning Reserves, Non-Spinning Reserves and Replacement Reserves from Generating Units operating within the ISO Control Area and from external imports of System Resources. Scheduling Coordinators are allowed to bid or self-provide their Regulation obligation in whole or in part from resources located outside the ISO Control Area by dynamically scheduling such resources. Each System Resource used to bid or self-provide Regulation must comply with the Dynamic Scheduling Protocol in Appendix X.

8.3.3 Certification and Testing Requirements.

Each Generating Unit, System Unit, Load, or System Resource that is allowed to bid or self-provide Ancillary Services under this Tariff must comply with the ISO's certification and testing requirements. Each Generating Unit and System Unit used to bid Regulation or used to self-provide Regulation must have been certified and tested by the ISO using the process defined in Part A of Appendix K, Each System Resource used to bid or self-provide Regulation must comply with the Dynamic Scheduling Protocol in Appendix X. Spinning Reserve may be provided only from Generating Units, System Resources from external imports, or System Units, which have been certified and tested by the ISO using the process defined in Appendix K, Non-Spinning Reserve and Replacement Reserve may be provided from Loads, Demand which can be reduced by Dispatch, interruptible exports, on-demand rights from other entities or Control Areas, Generating Units, System Resources from external imports, or System Units, which have been certified and tested by the ISO using the process defined in – Parts C & D of Appendix K, respectively, Voltage Support may only be provided from resources including Loads, Generating Units and System Units which have been certified and tested by the ISO using the process defined in Part E of Appendix K, Black Start capability may only be provided from Generating Units which have been certified and tested by the ISO using the process defined in Part F of Appendix K. ISO certification to provide ancillary services may be revoked by the ISO under the provisions of this Tariff and Parts A-F of Appendix K.

8.3.4 The ISO shall procure on a daily and hourly basis, each day, Regulation, Spinning, Non-Spinning and Replacement Reserves. The ISO shall procure Replacement Reserve on a longer-term basis pursuant to Section 42.1.3 if necessary to meet reliability criteria. The ISO Governing Board must approve all long-term Replacement Reserve contracts. The ISO shall contract for Voltage Support annually (or for such other period as the ISO may determine is economically advantageous) and on a daily or hourly basis as required to maintain System Reliability. The ISO shall contract annually (or for such other period as the ISO may determine is economically advantageous) for Black Start Generation.

8.4 Technical Requirements for Providing Ancillary Services.

All Generating Units, System Units, Loads and System Resources providing Ancillary Services shall comply with the technical requirements set out in Sections 8.4.1 to 8.4.6.1 below relating to their operating capabilities, communication capabilities and metering infrastructure. No Scheduling Coordinator shall be permitted to submit a bid to the ISO for the provision of an Ancillary Service from a Generating Unit, System Unit, Load or System Resource, or to submit a Schedule for self-provision of an Ancillary Service from that Generating Unit, System Unit, Load or System Resource, unless the Scheduling Coordinator is in possession of a current certificate issued by the ISO confirming that the Generating Unit, System Unit, Load or System Resource complies with the ISO's technical requirements for providing the Ancillary Service concerned. Scheduling Coordinators can apply for Ancillary Services certificates in accordance with the ISO's Protocols for considering and processing such applications. The ISO shall have the right to inspect Generating Units, Loads or the individual resources comprising System Units and other equipment for the purposes of the issue of a certificate and periodically thereafter to satisfy itself that its technical requirements continue to be met. If at any time the ISO's technical requirements are not being met, the ISO may withdraw the certificate for the Generating Unit, System Unit, Load or System Resource concerned.

(c) the scheduling information provided by the Scheduling Coordinator is deemed to be valid in accordance with Appendix E and the ISO Protocols; and

(d) the Generating Units, System Units, Loads or System Resources meet the ISO's locational requirements for the Ancillary Services.

8.7 Scheduling of Units to Provide Ancillary Services.

The ISO shall prepare supplier schedules for Ancillary Services (both self-provided and purchased by the ISO) for the Day-Ahead and the Hour-Ahead Markets. The ISO shall notify each Scheduling Coordinator no later than 1:00 p.m. of the day prior to the Trading Day of their Ancillary Services schedules for the Day-Ahead and no later than one hour prior to the operating hour of their Ancillary Services schedules for the Hour-Ahead. Where long-term contracts are involved, the information may be treated as standing information for the duration of the contract.

If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day and before the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day, the ISO determines that it requires Ancillary Services in addition to those included in the Final Day-Ahead Schedule (in the appropriate Zone if procuring zonally), the ISO may procure such additional Ancillary Services by providing Scheduling Coordinators with amended supplier schedules for the Day-Ahead Markets that include Ancillary Services for which previously submitted (but not selected) bids remain available and have not previously been withdrawn. The ISO shall select such Ancillary Services in price merit order (and in the relevant Zone if the ISO is procuring Ancillary Services on a Zonal basis). Such amended supplier schedules shall be provided to the Scheduling Coordinators no later than the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day.

Once the ISO has given Scheduling Coordinators notice of the Day-Ahead and Hour-Ahead Schedules, these schedules represent binding commitments made in the markets between the ISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above. Any minimum energy input and output associated with Regulation and Spinning Reserve services shall be the responsibility of the Scheduling Coordinator, or provided in accordance with the must-offer obligation as

set forth in Section 40.7, as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units or System Units, if any, bidding to provide these services. Accordingly, except as set forth under Section 40.7, the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating Units or System Units, if any, to facilitate delivery of Energy from Ancillary Services.

Notwithstanding the foregoing, a Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace that capacity in whole or in part from the ISO if the scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or if the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be the Market Clearing Price in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the Zone in which the Generating Units or other resources are located. The ISO will purchase the Ancillary Service concerned from another Scheduling Coordinator in the Hour-Ahead Market in accordance with the provisions of the ISO Tariff.

8.8 Black Start.

(a) Black Start shall meet the standards specified for Black Start in this Tariff and Appendix K; and

(b) the ISO will Dispatch Black Start as required in accordance with the applicable Black Start agreement.

8.9 [Not Used]

8.10 Verification, Compliance Testing, and Audit of Ancillary Services.

Availability of both contracted and self-provided Ancillary Services shall be verified by the ISO by unannounced testing of Generating Units, Loads and System Resources, by auditing of response to ISO

(b) if the Owner has elected Option B of Schedule G, three times the start-up cost specified in Schedule D to the applicable RMR Contract for any start-up incurred, and the rate specified in Equation 1a or 1b below times the amount of energy delivered in response to the ISO's instruction.

Equation 1a

$$\text{Energy Price (\$/MWh)} = \frac{(AX^3 + BX^2 + CX + D) * P * E}{X} + \text{Variable O\&M Rate}$$

Equation 1b

$$\text{Energy Price (\$/MWh)} = \frac{A * (B + CX + De^{FX}) * P * E}{X} + \text{Variable O\&M Rate}$$

Where:

- for Equation 1a, A, B, C, D and E are the coefficients given in Table C1-7a of the applicable RMR Contract;
- for Equation 1b, A, B, C, D, E and F are the coefficients given in Table C1-7b of the applicable RMR Contract;
- X is the Unit output level during the applicable settlement period, MWh;
- P is the Hourly Fuel Price as calculated by Equation C1-8 in Schedule C using the Commodity Prices in accordance with the applicable RMR Contract;
- Variable O&M Rate ($/MWh): as shown on Table C1-18 of the applicable RMR Contract.

11.2.4.2.1 Allocation of Costs Resulting From Dispatch Instructions.

Pursuant to Section 11.2.4.1, the ISO may, at its discretion, Dispatch any Participating Generator, Participating Load and dispatchable System Resource that has not bid into the Imbalance Energy or Ancillary Services markets, to avoid an intervention in market operations or to prevent or relieve a System Emergency. Such Dispatch may result from, among other things, planned and unplanned transmission facility Outages; bid insufficiency in the Ancillary Services and real-time Energy markets; and location-

specific requirements of the ISO. The cost associated with each Dispatch instruction is broken into two components:

a) the portion of the Energy payment at or below the Market Clearing Price ("MCP") for the Settlement Interval, and

b) the portion of the Energy payment above the MCP, if any, for the Settlement Interval.

For each Settlement Interval, costs above the MCP incurred by the ISO for such Dispatch instructions necessary as a result of a transmission facility Outage or in order to satisfy a location-specific requirement in that Settlement Interval shall be payable to the ISO by the Participating Transmission Owner in whose PTO Service Territory the transmission facility is located or the location-specific requirement arose. The costs incurred by the ISO for such Dispatch instructions for reasons other than for a transmission facility Outage or a location-specific requirement will be recovered in the same way as for Instructed Imbalance Energy.

11.2.4.2.1.1 Allocation of Costs from Out-Of-Market calls to Condition 2 RMR Units.

All costs associated with energy provided by a Condition 2 RMR Unit operating other than according to a dispatch notice issued under the RMR Contract shall be allocated in accordance with Section 11.2.4.2.1. Until either the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups exceed the relevant RMR Contract Service Limit, any cost incurred for energy provided under the RMR Contract above the rate specified in equation 1a or 1b as set forth in Section 11.2.4.2 shall be allocated in accordance with Section 11.2.4.2.1, not to the Responsible Utility.

Start-Up Costs for Condition 2 RMR Units providing service outside the RMR Contract, and any additional Start-Up Cost associated with a Condition 2 RMR Unit providing service under the RMR Contract when the unit's total service has exceeded an RMR Contract Service Limit but neither the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups have exceeded the applicable RMR Contract Service Limit, shall be invoiced in accordance with Section 40.12.6 and collected in accordance with Section 40.12.1.

11.2.10 Payments Under Section 42.1 Contracts.

The ISO shall calculate and levy charges for the recovery of costs incurred under contracts entered into by the ISO under the authority granted in Section 42.1 in accordance with Section 42.1.8 of this ISO Tariff.

11.2.11 Obligation for FERC Annual Charges.

11.2.11.1 Each Scheduling Coordinator shall be obligated to pay for the FERC Annual Charges for its use of the ISO Controlled Grid to transmit electricity, including any use of the ISO Controlled Grid through Existing Contracts scheduled by the Scheduling Coordinator. Any FERC Annual Charges to be assessed by FERC against the ISO for such use of the ISO Controlled Grid shall be assessed against Scheduling Coordinators at the FERC Annual Charge Recovery Rate, as determined in accordance with this Section 11.2.11. Such assessment shall be levied monthly against all Scheduling Coordinators based upon each Scheduling Coordinator's metered Demand and exports.

11.2.11.2 Scheduling Coordinators may elect, each year, to pay the FERC Annual Charges assessed against them by the ISO either on a monthly basis or an annual basis. Scheduling Coordinators that elect to pay FERC Annual Charges on a monthly basis shall make payment for such charges within five (5) Business Days after issuance of the monthly invoice. The FERC Annual Charges will be issued to Market Participants once a month, on the first business day after the final market and Grid Management Charge invoices are issued for the trade month. Once the final FERC Annual Charge Recovery Rate is received from FERC in the Spring/Summer of the following year, a supplemental invoice will be issued. Scheduling Coordinators that elect to pay FERC Annual Charges on an annual basis shall make payment for such charges within five (5) Business Days after the ISO issues such supplemental invoice. Scheduling Coordinators that elect to pay FERC Annual Charges on an annual basis shall maintain either an Unsecured Credit Limit or shall maintain Financial Security in accordance with Section 12.1.

11.2.12 FERC Annual Charge Trust Account.

All funds collected by the ISO for FERC Annual Charges shall be deposited in the FERC Annual Charge Trust Account. The FERC Annual Charge Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time. The ISO shall disburse funds from the FERC Annual Charge Trust Account in order to pay the FERC any and all FERC Annual Charges assessed against the ISO.

11.2.13 Determination of the FERC Annual Charge Recovery Rate.

11.2.13.1 The FERC Annual Charge Recovery Rate shall be set at the projected total FERC Annual Charge obligation with regard to transactions on the ISO Controlled Grid during the year in which the FERC Annual Charge Recovery Rate is collected, adjusted for interest projected to be earned on the monies in the FERC Annual Charge Trust Account ("Annual Charge Obligation"), divided by the projected Demand and exports during that year for all entities subject to assessment of FERC Annual Charges by the ISO ("Annual Charge Demand"). The FERC Annual Charge Recovery Rate for the period from January 1, 2001 until the first adjustment of the FERC Annual Charge Recovery Rate goes into effect shall be posted on the ISO Home Page at least fifteen (15) days in advance of the date on which the initial rate will go into effect.

11.2.13.2 The ISO may adjust the FERC Annual Charge Recovery Rate on a quarterly basis, as necessary, to reflect the net effect of the following:

(a) the difference, if any, between actual Annual Charge Demand and projected Annual Charge Demand during the year-to-date;

(b) the difference, if any, between the projections of the Annual Charge Obligation and the Annual Charge Demand upon which the charge for the year is based and the ISO's most current projections of those values, provided that the projection of the Annual Charge Obligation may only be adjusted on an annual basis for changes in the Federal Energy Regulatory Commission's budget for its electric regulatory program or changes in the projected total transmission volumes subject to assessment of FERC Annual Charges;

(c) the difference, if any, between actual and projected interest earned on funds in the FERC Annual Charge Trust Account; and

(d) any positive or negative balances of funds collected for FERC Annual Charges in a previous year after all invoices for FERC Annual Charges for that year have been paid by the ISO, other than those that are addressed through the mechanism described in Section 11.2.13.4.

11.2.13.3 The adjusted FERC Annual Charge Recovery Rate shall take effect on the first day of the calendar quarter. The ISO shall publish all data and calculations used by the ISO as a basis for such an adjustment on the ISO Home Page at least fifteen (15) days in advance of the date on which the new rate shall go into effect.

11.2.13.4 If the FERC Annual Charges assessed by FERC against the ISO for transactions on the ISO Controlled Grid during any year exceed or fall short of funds collected by the ISO for FERC Annual Charges with respect to that year by a range of 10% or less, the ISO shall take such under- or over-recovery into account through an adjustment to the FERC Annual Charge Recovery Rate in accordance with Section 11.2.13.2. Any deficiency of available funds necessary to pay for any assessment of FERC Annual Charges payable by the ISO may be covered by an advance of funds from the ISO's Grid Management Charge, provided any such advanced funds will be repaid. If the ISO's collection of funds for FERC Annual Charges with respect to any year results in an under- or over-recovery of greater than 10%, the ISO shall either assess a surcharge against all active Scheduling Coordinators for the amount under-recovered or shall issue a credit to all active Scheduling Coordinators for the amount over-recovered. Such surcharge or credit shall be allocated among all active Scheduling Coordinators based on the percentage of each active Scheduling Coordinators metered Demand and exports during the relevant year. For purposes of this section, an "active Scheduling Coordinator" shall be a Scheduling Coordinator certified by the ISO in accordance with Section 4.5.1 of this ISO Tariff at the time the ISO issues a surcharge or credit under this section. The ISO will issue any surcharges or credits under this section within 60 days of receiving a FERC Annual Charge assessment from the FERC.

11.2.14 Credits and Debits of FERC Annual Charges Collected from Scheduling Coordinators.

In addition to the surcharges or credits permitted under Sections 11.2.13 or 11.6.3.3 of this ISO Tariff, the ISO shall credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of FERC Annual Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

11.2.15 The ISO shall calculate the amount due from each UDC or MSS, or from a Scheduling Coordinator delivering Energy for the supply of Gross Load not directly connected to the facilities of a UDC or MSS, for the High Voltage Access Charge and Transition Charge in accordance with operating procedures posted on the ISO Home Page. These charges shall accrue on a monthly basis.

11.2.16 Emissions and Start-Up Fuel Cost Charges.

The ISO shall calculate, account for and settle charges and payments for Emissions Costs and Start-Up Fuel Costs in accordance with Sections 40.11 and 40.12 of this ISO Tariff.

11.2.17 The ISO shall calculate, charge and disburse all collected default Interest in accordance with the ISO Tariff.

11.2.18 Auditing

All of the data, information, and estimates the ISO uses to calculate these amounts shall be subject to the auditing requirements of Section 10.2.11 of the ISO Tariff. The ISO shall calculate these amounts using the software referred to in Section 11.4. 4except in cases of system breakdown when it shall apply the procedures set out in 11.9a (Emergency Procedures).

11.3 Billing and Payment Process.

The ISO will calculate for each charge the amounts payable by the relevant Scheduling Coordinator, Black Start Generator or Participating TO for each Settlement Period of the Trading Day, and the amounts payable to that Scheduling Coordinator, Black Start Generator or Participating TO for each charge for each Settlement Period of that Trading Day and shall arrive at a net amount payable for each

11.8.5 Use of Accounts.

11.8.5.1 Clearing Account

(a) Subject to Section 11.3.3 each ISO Debtor shall remit to the ISO Clearing Account the amount shown on the invoice as payable by that ISO Debtor for value not later than 10:00 am on the Payment Date.

(b) On the Payment Date the ISO shall be entitled to cause the transfer of such amounts held in a Scheduling Coordinator's ISO prepayment account to the ISO Clearing Account as provided in Section 11.3.3.

The ISO shall calculate the amounts available for distribution to ISO Creditors on the Payment Date and shall give irrevocable instructions to the ISO Bank to remit from the ISO Clearing Account to the relevant Settlement Accounts maintained by the ISO Creditors, the aggregate amounts determined by the ISO to be available for payment to ISO Creditors for value by close of business on the Payment Date if no ISO Debtors are in default. If an ISO Debtor is in default and until all defaulting amounts have been collected, the ISO shall make payments as soon as practical within five (5) business days of the collection date posted in the ISO Payments Calendar. If required, the ISO shall instruct the ISO Bank to transfer amounts from the ISO Reserve Account to enable the ISO Clearing Account to clear.

The ISO is authorized to instruct the ISO Bank to debit the ISO Clearing Account and transfer to the relevant ISO account sufficient funds to pay in full the Grid Management Charge falling due on any Payment Day with priority over any other payments to be made on that or on subsequent days out of the ISO Clearing Account.

11.8.5.2 Reserve Account.

The ISO Reserve Account shall be available to the ISO for the purpose of providing funds to clear the ISO Clearing Account in the event that there are insufficient funds in the ISO Clearing Account to pay ISO Creditors. If there are insufficient funds in the ISO Clearing Account to pay ISO Creditors and clear the account on any Payment Date, due to payment default by one or more ISO Debtors, the ISO shall

transfer funds from the ISO Reserve Account to the ISO Clearing Account to clear it by close of banking business on that Payment Date pursuant to Section 11.12.2.2.

If the ISO Reserve Account is drawn upon, the ISO shall as soon as possible thereafter take any necessary steps against the defaulting Scheduling Coordinator, including making any calculations or taking any other appropriate action, to replenish the ISO Reserve Account including drawing on any credit support provided by the defaulting Scheduling Coordinator pursuant to Section 12.1 of this ISO Tariff or serving demands on any defaulting Scheduling Coordinators with an Unsecured Credit Limit.

The proceeds of drawings under any line of credit or other credit facility of the ISO Reserve Account shall be held on trust for ISO Creditors. If the Reserve Account is replenished as provided for in 11.8.5.2.1, any credits shall be held on trust for all ISO Creditors.

11.8.5.2.1 Replenishing the ISO Reserve Account Following Payment Default.

If the ISO has debited the ISO Reserve Account then:

(a) If, after the ISO has debited the ISO Reserve Account on a Payment Date, the ISO Bank receives a remittance from an ISO Debtor which has not been (but should have been, if it had been received on a timely basis) credited to the ISO Clearing Account by 10:00 am on the Payment Date and which required the debiting of the ISO Reserve Account, such remittance shall be credited to the ISO Reserve Account.

(b) The proceeds of any enforcement of Security and/or amounts recovered under proceedings shall be credited to the ISO Reserve Account.

(c) If after taking reasonable action the ISO determines that the Default Amount (or any part) and/or Interest cannot be recovered, such amounts shall be deemed to be owing by those Market Participants who were ISO Creditors on the relevant Payment Date pro rata to the net payments they received on that Payment Date and shall be accounted for by way of a charge in the next

11.24.4 Calendar Content and Format

The ISO may change the content or format of the ISO Payments Calendar. The ISO may also produce a summary outline of the Settlement and billing cycles.

11.24.5 Update the Final Payments Calendar.

If as a result of a tariff amendment approved by FERC, the final ISO Payments Calendar developed in accordance with Section 11.24 is rendered inconsistent with the timing set forth in the tariff, the ISO shall update the final ISO Payments Calendar to make it consistent with the tariff as approved by FERC on the date on which the tariff amendment goes into effect. The ISO shall simultaneously send out a notice to Market Participants that the final ISO Payments Calendar has been revised.

12 CREDITWORTHINESS.

12.1 Credit Requirements.

The creditworthiness requirements in this section apply to the ISO's acceptance of Schedules, to all transactions in an ISO Market, to the payment of charges pursuant to the ISO Tariff (including the Grid Management Charge), and to establish credit limits for participation in any ISO auction of FTRs. Each Market Participant (including each Scheduling Coordinator, UDC, or MSS) or FTR Bidder shall secure its financial transactions with the ISO (including its participation in any auction of FTRs) by maintaining an Unsecured Credit Limit and/or by posting Financial Security, the level of which constitutes the Market Participant's or FTR Bidder's Financial Security Amount. For each Market Participant or FTR Bidder, the sum of its Unsecured Credit Limit and its Financial Security Amount shall represent its Aggregate Credit Limit. Each Market Participant or FTR Bidder shall have the responsibility to maintain an Aggregate Credit Limit that is at least equal to its Estimated Aggregate Liability.

12.1.1 Unsecured Credit Limit.

Each Market Participant or FTR Bidder requesting an Unsecured Credit Limit shall submit an application to the ISO in the form specified on the ISO Home Page. The ISO shall determine the Unsecured Credit Limit for each Market Participant or FTR Bidder in accordance with the procedures set forth in the ISO Credit Policy & Procedures Guide posted on the ISO Home Page. The maximum Unsecured Credit Limit for any Market Participant or FTR Bidder shall be $250 million. In accordance with the procedures described in the ISO Credit Policy & Procedures Guide, each Market Participant or FTR Bidder requesting or maintaining an Unsecured Credit Limit is required to submit to the ISO or its agent financial statements and other information related to its overall financial health as directed by the ISO. Each Market Participant or FTR Bidder is responsible for the timely submission of its latest financial statements as well as other information that may be reasonably necessary for the ISO to conduct its evaluation. The ISO shall determine the Unsecured Credit Limit for each Market Participant or FTR Bidder as described in subsections 12.1.1A, 12.1.1A.1, 12.1.1A.2 and 12.1.1A.3.

12.1.1A Unsecured Credit Limit Calculation.

An Unsecured Credit Limit (UCL) for each Public/Private Corporation or Governmental Entity that requests an unsecured limit is calculated as follows:

1. Rated Public/Private Corporations – the UCL is the lesser of $250 million or an amount equal to the Market Participant's or FTR Bidder's Tangible Net Worth (TNW) multiplied by a calculated percentage of TNW. The TNW percentage is comprised of 50 percent (50%) of the Market Participant's or FTR Bidder's Credit Rating Default Probability and 50 percent (50%) of the MKMV Default Probability.

2. Unrated Public/Private Corporations – the UCL is the lesser of $250 million or an amount equal to the Market Participant's or FTR Bidder's Tangible Net Worth (TNW) multiplied by a calculated percentage of TNW. The TNW percentage is comprised of 100 percent of the MKMV Default Probability.

3. Rated Governmental Entities – the UCL is the lesser of $250 million or an amount equal to the Market Participant's or FTR Bidder's Net Assets (NA) multiplied by a calculated percentage of NA. The NA percentage is comprised of 100 percent of the Market Participant's or FTR Bidder's Credit Rating Default Probability.

4. Unrated Governmental Entities – the UCL is the lesser of $250 million or an amount equal to a given percentage of the Market Participant's or FTR Bidder's Net Assets if the Market Participant or FTR Bidder has a minimum of $25 million in Net Assets and its Times Interest Earned, Debt Service Coverage and Equity to Assets ratios meet or exceed specified minimums.

The $250 million hard cap on UCLs specified in the ISO Tariff has been set with respect to the length of the current ISO payment calendar, i.e., a maximum of 95 days of charges outstanding. Upon implementation of Payment Acceleration (scheduled for 2008), we expect to recommend a reduction in the $250 million hard cap. Any changes to the $250 million cap will require FERC approval of an amendment to the applicable provisions of the ISO Tariff.

12.1.1A.1 Maximum Percentage of TNW and NA.

For Rated and Unrated Public/Private Corporations or Rated Governmental Entities, the maximum percentage of TNW or NA is 7.5 percent (7.5%) if the Market Participant's or FTR Bidder's Combined Default Probability is less than or equal to 0.06 percent (0.06%).

The Maximum Allowable Percentage of 7.5% is for the highest quality firms; that is, those Market Participants and FTR Bidders with a CDP of 0.06 percent or less. The TNWP or NAP that a Market Participant or FTR Bidder qualifies for will be reduced as its credit risk increases.

For Unrated Governmental Entities, the ISO may provide an Unsecured Credit Limit of up to 5 percent (5%) of NA.

With respect to either of these potential maximum percentages, a lesser amount of unsecured credit may be granted if the ISO becomes aware of information related to a Material Change in Financial Condition or other significant information that presents a significant risk to the creditworthiness of the entity.

12.1.1A.2 Unsecured Credit Limit Calculation Steps.

An eight-step process is used to determine Unsecured Credit Limits for Market Participants and FTR Bidders that are Rated Public/Private Corporations, Unrated Public/Private Corporations and Rated Governmental Entities. Criteria for Unsecured Credit Limits for Unrated Governmental Entities is discussed in Section 12.1.1A.3.

Step 1 – If the Market Participant or FTR Bidder has a credit rating(s) from one or more of the "Nationally Recognized Statistical Rating Organizations" (NRSRO), verify the rating(s) with the appropriate NRSRO.

Step 2 - Calculate the Market Participant's or FTR Bidder's Average Rating Default Probability (ARDP).

a. ARDP is the sum of Credit Rating Default Probabilities divided by the total number of Credit Rating Default Probabilities used.

b. The following table shows the median default probability calculated by Moody's KMV (i.e., MKMV) for Standard & Poor's and Moody's long-term credit rating classes. Default probabilities are available from each NRSRO.

c. The example presented below uses the following table to derive the ARDP.

CREDIT RATING DEFAULT PROBABILITIES (DP)
Based on 5 year historical median of Moody's KMV EDF's*

Maximum Allowable Percentage)	**7.50%**
Base Default Probability	**0.06%**

Moody's	5 Year Median Default Probability	Tangible Net Worth or Net Asset Percentage	S&P	5 Year Median Default Probability	Tangible Net Worth or Net Asset Percentage
Aaa	0.020%	7.50%	AAA	0.020%	7.50%
Aa1	0.032%	7.50%	AA+	0.033%	7.50%
Aa2	0.040%	7.50%	AA	0.042%	7.50%
Aa3	0.056%	7.50%	AA-	0.059%	7.50%
A1	0.080%	5.60%	A+	0.084%	5.38%
A2	0.114%	3.94%	A	0.119%	3.80%
A3	0.144%	3.12%	A-	0.154%	2.92%
Baa1	0.182%	2.47%	BBB+	0.200%	2.25%
Baa2	0.230%	1.95%	BBB	0.259%	1.73%
Baa3	0.307%	1.47%	BBB-	0.367%	1.23%
Ba1	0.408%	1.10%	BB+	0.518%	0.00%
Ba2	0.544%	0.00%	BB	0.733%	0.00%
Ba3	0.848%	0.00%	BB-	1.215%	0.00%
B1	1.323%	0.00%	B+	2.014%	0.00%
B2	2.064%	0.00%	B	3.338%	0.00%
B3	4.168%	0.00%	B-	5.384%	0.00%
Caa1	8.418%	0.00%	CCC+	8.682%	0.00%
Caa2	17.000%	0.00%	CCC	14.000%	0.00%
Caa3	17.946%	0.00%	CCC-	14.936%	0.00%
Ca	20.000%	0.00%	CC	17.000%	0.00%
C	20.000%	0.00%	C	18.250%	0.00%
			D	20.000%	0.00%

* Table is subject to update on a monthly basis

d. Issuer ratings without the benefit of credit enhancement would be used in this assessment. Such ratings are also known as "counterparty" or "underlying" ratings.

Step 3 – Using MKMV's CreditEdge or RiskCalc software, obtain the Market Participant's or FTR Bidder's MKMV Default Probability (MKDP).

a. Since MKMV calculates default probabilities directly, the MKMV Default Probability will be used without any mapping.

Step 4 – Calculate a Combined Default Probability (CDP) based on one of the following methodologies:

a. CDP for Rated Public/Private Corporations = (ARDP * 50%) + (MKDP * 50%)

b. CDP for Unrated Public/Private Corporations = MKDP * 100%

c. CDP for Rated Governmentally Owned Utilities = ARDP * 100%

Step 5 – Calculate the Market Participant's or FTR Bidder's Tangible Net Worth Percentage (TNWP) or Net Assets Percentage (NAP).

a. TNWP = MAP * BDP / CDP for Rated/Unrated Public/Private Corporations

b. NAP = MAP * BDP / CDP for Rated Governmental Entities

Where:

MAP = Maximum Allowable Percentage;

BDP = Base Default Probability;

CDP = see Step 4 above; and

If the SC's CDP > 0.5%, the TNWP or NAP equals 0%

Step 6 – Calculate the Market Participant's or FTR Bidder's Tangible Net Worth or Net Assets.

a. TNW for Rated/Unrated Public/Private Corporations = Assets minus Intangibles (e.g., Good Will) minus Liabilities

b. NA for Rated Governmental Entities = Total Assets minus Total Liabilities

Step 7 – Calculate the Market Participant's or FTR Bidder's Unsecured Credit Limit.

a. UCL = TNW * TNWP for Rated/Unrated Public/Private Corporations

b. UCL = NA * NAP for Rated Governmental Entities

Step 8 – Adjust Unsecured Credit Limit Downward, if warranted based on the ISO's review of factors in Appendix Z, Section A-1.3.

a. Final UCL = UCL from Step 7 * (0 - 100%)

12.1.1A.3 Unsecured Credit Limit Calculations for Unrated Governmental Entities.

The UCL for an Unrated Governmental Entity is based on the financial ratios defined in the following table:

Ratio	Calculation	Minimum Accepted Value
Times Interest Earned (TIER)	(Long-Term Debt Interest Expense + Change in Net Assets) / Long-Term Debt Interest Expense	1.05
Debt Service Coverage (DSC)	(Depreciation & Amortization Expense + Long Term Debt Interest Expense + Change in Net Assets) / Debt Service Billed (Debt Service Interest and Principal).	1.00
Equity to Assets	Total Equity / Total Assets	0.15

For those Municipals that meet all of the above criteria, initial unsecured credit will be calculated as five percent (5%) of Net Assets (i.e., Total Assets minus Total Liabilities). That percentage may be adjusted downward by up to 100% if the ISO becomes aware of significant negative information regarding the Market Participant's or FTR Bidder's operations as determined through trade publications and/or the financial press.

12.1.1.1 Other Procedures Regarding Unsecured Credit Limits.

As a result of the ISO's credit evaluation, a Market Participant or FTR Bidder may be given an Unsecured Credit Limit by the ISO or denied an Unsecured Credit Limit with the ISO. Following the initial application and the establishment of an Unsecured Credit limit, the ISO will review each Market Participant's or FTR Bidder's Unsecured Credit Limit on a quarterly basis, unless that entity does not prepare quarterly statements, in which case the review will occur on an annual basis, and no entity shall be required to submit a new application. In addition, the ISO may review the Unsecured Credit Limit for any Market Participant or FTR Bidder whenever the ISO becomes aware of information that could indicate a Material Change in Financial Condition. In the event the ISO determines that the Unsecured Credit Limit of a Market Participant or FTR Bidder must be reduced as a result of a subsequent review, the ISO shall notify the Market Participant or FTR Bidder of the reduction, and shall, upon request, also provide the Market Participant or FTR Bidder with a written explanation of why the reduction was made.

12.1.1.2 Determination of Unsecured Credit Limits for Affiliates.

If any Market Participant or FTR Bidder requesting or maintaining an Unsecured Credit Limit is affiliated with one or more other entities subject to the credit requirements of this Section 12, the ISO may consider the overall creditworthiness and financial condition of such Affiliates when determining the applicable Unsecured Credit Limit. The ISO may determine that the maximum Unsecured Credit Limit specified in Section 12.1.1 applies to the combined activity of such Affiliates. In the event the ISO determines that the maximum Unsecured Credit Limit applies to the combined activity of the Affiliates and the Market Participant, the ISO shall inform the Market Participant in writing.

12.1.1.3 Notification of Material Change in Financial Condition.

Each Market Participant or FTR Bidder shall notify the ISO in writing of a Material Change in Financial Condition, within five (5) Business Days of when the Material Change in Financial Condition is known or reasonably should be known by the Market Participant or FTR Bidder. The provision to the ISO of a copy of a Form 10-K, 10-Q, or Form 8-K filed with the U.S. Securities and Exchange Commission shall satisfy the requirement of notifying the ISO of such Material Change in Financial Condition. Alternatively, the Market Participant may direct the ISO to the location of the information on their company website or the website of the U.S. Securities & Exchange Commission.

12.1.1.4 Transition from Credit Provisions that Were in Effect Prior to the Effective Date of this Section 12.1.1, *et seq.*

Each Market Participant or FTR Bidder that, prior to the effective date of this Section 12.1.1, *et seq.*, maintained an "Approved Credit Rating" with respect to market and/or Grid Management Charge obligations, shall be assigned a maximum Unsecured Credit Limit of $250 million for a period not to exceed thirty (30) days. Such thirty-day period shall start on the date the ISO issues a market notice stating that FERC has issued an order making Section 12.1.1, *et seq.* effective. Prior to or during such thirty-day period, each Market Participant or FTR Bidder maintaining an "Approved Credit Rating" as described herein shall submit to the ISO the information that is required for the ISO to make a credit evaluation regarding the Market Participant or FTR Bidder as described in Section 12.1.1. If the Market Participant or FTR Bidder does not submit the required information within the thirty-day period described

herein, the ISO shall assign an Unsecured Credit Limit of $0 to the Market Participant or FTR Bidder until the required information has been submitted.

Each Market Participant or FTR Bidder that, prior to the effective date of this Section 12.1.1, *et seq.*, did not maintain an "Approved Credit Rating" with respect to market and/or Grid Management Charge obligations, shall be assigned an Unsecured Credit Limit of $0 until the Market Participant or FTR Bidder submits to the ISO the information that is required for the ISO to make a credit evaluation regarding the Market Participant or FTR Bidder as described in Section 12.1.1.

12.1.2 Financial Security and Financial Security Amount.

A Market Participant or FTR Bidder that does not have an Unsecured Credit Limit, or that has an Unsecured Credit Limit that is less than its Estimated Aggregate Liability, shall post Financial Security that is acceptable to the ISO and that is sufficient to ensure that its Aggregate Credit Limit (*i.e.*, the sum of its Unsecured Credit Limit and Financial Security Amount) is equal to or greater than its Estimated Aggregate Liability. The Financial Security posted by a Market Participant or FTR Bidder may be any combination of the following types of Financial Security provided in favor of the ISO and notified to the ISO under Section 12.3:

(a) an irrevocable and unconditional letter of credit issued by a bank or financial institution that is reasonably acceptable to the ISO;

(b) an irrevocable and unconditional surety bond issued by an insurance company that is reasonably acceptable to the ISO;

(c) an unconditional and irrevocable guaranty issued by a company that is reasonably acceptable to the ISO;

(d) a cash deposit standing to the credit of the ISO in an interest-bearing escrow account maintained at a bank or financial institution that is reasonably acceptable to the ISO;

(e) a certificate of deposit in the name of the ISO issued by a bank or financial institution that is reasonably acceptable to the ISO;

(f) a payment bond certificate in the name of the ISO issued by a bank or financial institution that is reasonably acceptable to the ISO; or

(g) a prepayment to the ISO.

Financial Security instruments as listed above shall be in such form as the ISO may reasonably require from time to time by notice to Market Participants or FTR Bidders, or in such other form as has been evaluated and approved as reasonably acceptable by the ISO. The ISO shall publish and maintain standardized forms related to the types of Financial Security listed above on the ISO Home Page. The ISO shall require the use of standardized forms of Financial Security to the greatest extent possible.

12.1.2.1 Process for Evaluating Requests to Use Non-Standardized Forms of Financial Security.

A Market Participant or FTR Bidder that seeks permission to use a form for Financial Security other than one or more of the standardized forms posted on the ISO Home Page shall seek such permission in a written request to the ISO that explains the basis for the use of such non-standardized form. The ISO shall have ten (10) Business Days from receipt of such request to evaluate it and determine whether it will be approved as reasonably acceptable. If the ISO does not respond to such request within the ten (10) Business Day period, the request shall be deemed to have been denied. Until and unless the ISO approves the use of a non-standardized form for Financial Security, the Market Participant or FTR Bidder that submitted such request shall be required to use one of the standardized forms for Financial Security described in this Section 12.1.2.

12.1.2.2 Expiration of Financial Security.

Each Market Participant or FTR Bidder shall ensure that the financial instruments it uses for the purpose of providing Financial Security will not expire and thereby cause the Market Participant's or FTR Bidder's Aggregate Credit Limit to fall below the Market Participant's or FTR Bidder's Estimated Aggregate Liability. The ISO will treat a financial instrument that does not have an automatic renewal provision and that is not renewed or replaced within seven (7) days of its date of expiration as being out of compliance with the standards for Financial Security contained in this Section 12 and will deem the value of such

financial instrument to be zero, and will draw upon such Financial Security prior to its stated expiration if deemed necessary by the ISO.

12.1.2.3 Risk of Loss of Financial Security Amounts Held and Invested by the ISO.

In accordance with the ISO's investment policy, the ISO will invest each Financial Security Amount of a Market Participant or FTR Bidder only in bank accounts, high-quality money market accounts, and/or U.S. Treasury/Agency securities unless a specific written request is received from the Market Participant or FTR Bidder for a different type of investment and the ISO provides its written consent to such alternative investment. A Market Participant or FTR Bidder that provides a Financial Security Amount that is held and invested by the ISO on behalf of the Market Participant or FTR Bidder will bear all risks that such Financial Security Amount will incur a loss of principal and/or interest as a result of the ISO's investment of such Financial Security Amount.

12.1.3 Self-Supply of UDC Demand.

Notwithstanding anything to the contrary in the ISO Tariff, a Scheduling Coordinator or UDC that is an Original Participating Transmission Owner or is a Scheduling Coordinator for an Original Participating Transmission Owner shall not be precluded by Section 12.3 from scheduling transactions that serve a UDC's Demand from –

(1) a resource that the UDC owns; and

(2) a resource that the UDC has under contract to serve its Demand.

12.1.4 Allocation of Aggregate Credit Limit for FTR Auction Participation.

An FTR Bidder may elect to allocate a portion of its Aggregate Credit Limit toward satisfying the credit requirements for participating in auctions of FTRs, as set forth in Section 36.2.6.

12.1.5 Estimated Aggregate Liability.

The ISO will periodically calculate the Estimated Aggregate Liability of each Market Participant and FTR Bidder, based on all charges and settlement amounts for which such Market Participant or FTR Bidder is

liable or reasonably anticipated by the ISO to be liable for pursuant to the ISO Tariff. The Estimated Aggregate Liability for each Market Participant or FTR Bidder shall be determined and applied by the ISO consistent with the procedures set forth in the ISO Credit Policy & Procedures Guide posted on the ISO Home Page. The ISO shall upon request provide each Market Participant or FTR Bidder with information concerning the basis for the ISO's determination of its Estimated Aggregate Liability, and the ISO's determination may be disputed in accordance with the procedures set forth in the ISO Credit Policy & Procedures Guide. The ISO shall compare each Market Participant's or FTR Bidder's Estimated Aggregate Liability against its Aggregate Credit Limit on a periodic basis.

12.2 Review of Creditworthiness.

The ISO may review the creditworthiness of any Market Participant or FTR Bidder which delays or defaults in making payments due under the ISO Tariff and, as a consequence of that review, may require such Market Participant or FTR Bidder, whether or not it an Unsecured Credit Limit, to provide credit support in the form of any of the following types of Financial Security:

(a) an irrevocable and unconditional letter of credit by a bank or financial institution reasonably acceptable to the ISO;

(b) a cash deposit standing to the credit of an interest-bearing escrow account maintained at a bank or financial institution designated by the ISO;

(c) an irrevocable and unconditional surety bond posted by an insurance company reasonably acceptable to the ISO;

(d) a payment bond certificate in the name of the ISO from a financial institution designated by the ISO; or

(e) a prepayment to the ISO.

The ISO may require the Market Participant or FTR Bidder to maintain such Financial Security for at least one (1) year from the date of such delay or default.

12.3 Posting and Releases of Financial Security.

Each Market Participant or FTR Bidder required to provide a Financial Security Amount under Section 12.1.2 shall notify the ISO of the initial Financial Security Amount that it wishes to provide at least fifteen (15) days in advance and shall ensure that the ISO has received such Financial Security Amount prior to the date the Market Participant commences activity through the ISO, or the date the FTR Bidder participates in the applicable auction of FTRs. A Market Participant or FTR Bidder may at any time increase its Financial Security Amount by providing additional Financial Security in accordance with Section 12.1.2. A Market Participant or FTR Bidder may request that its Financial Security Amount be reduced or released by making its request not fewer than fifteen (15) days prior to the date on which the reduction ore release is requested to occur. The ISO shall evaluate the request and inform the Market Participant or FTR Bidder within ten (10) Business Days either that a reduction or release of the Financial Security Amount is permissible, that a reduction or release of the Financial Security Amount is impermissible, or that the ISO requires more information from the Market Participant or FTR Bidder in order to make its determination. The ISO may decline to reduce or release a Financial Security Amount or may release a lesser amount for any of the following reasons:

(a) The Estimated Aggregate Liability for the Market Participant or FTR Bidder cannot be accurately determined due to a lack of supporting settlement charge information.

(b) The most recent liabilities of the Market Participant or FTR Bidder are volatile to a significant degree and a reduction or release of the Financial Security Amount would present a high likelihood that, after the Financial Security Amount was reduced or released, the Estimated Aggregate Liability for the Market Participant or FTR Bidder, as calculated by the ISO, would exceed its Aggregate Credit Limit.

(c) The Market Participant has provided notice or otherwise demonstrated that it is terminating or significantly reducing its participation in the ISO markets. The ISO may retain a portion of the Financial Security Amount to ensure that the Market Participant is adequately secured with respect to pending liabilities that relate to settlement re-runs or other liabilities for which the Market Participant may be responsible under this ISO Tariff.

12.4 Calculation of Ongoing Financial Security Requirements.

Following the date on which a Market Participant commences trading, if the Market Participant's Estimated Aggregate Liability, as calculated by the ISO, at any time exceeds its Aggregate Credit Limit, the ISO shall direct the Market Participant to post an additional Financial Security Amount within five (5) Business Days that is sufficient to ensure that the Market Participant's Aggregate Credit Limit is at least equal to its Estimated Aggregate Liability. The ISO shall also notify a Market Participant if at any time its Estimated Aggregate Liability exceeds 90% of its Aggregate Credit Limit. For the purposes of calculating the Market Participant's Estimated Aggregate Liability, the ISO shall include (1) outstanding charges for Trading Days for which Settlement data is available, and (2) an estimate of charges for Trading Days for which Settlement data is not yet available. To estimate charges for Trading Days for which Settlement data is not yet available, the ISO will consider available historical Settlement data, and other available operational and market data as described in the ISO Credit Policy & Procedures Guide posted on the ISO Home Page.

12.5 ISO Enforcement Actions Regarding Under-Secured Market Participants.

Following the date on which a Market Participant commences trading, if a Market Participant's Estimated Aggregate Liability, as calculated by the ISO, at any time exceeds its Aggregate Credit Limit, the ISO may take any or all of the following actions:

(a) The ISO may withhold a pending payment distribution.

(b) The ISO may limit trading, which may include rejection of Schedules and/or limiting other ISO market activity. In such case, the ISO shall notify the Market Participant of its action and the Market Participant shall not be entitled to submit further Schedules to the ISO until the Market Participant posts an additional Financial Security Amount that is sufficient to ensure that the Market Participant's Aggregate Credit Limit is at least equal to its Estimated Aggregate Liability.

(c) The ISO may require the Market Participant to post an additional Financial Security Amount in lieu of an Unsecured Credit Limit for a period of time.

(d) The ISO may restrict, suspend, or terminate a Market Participant's Service Agreement.

In addition, the ISO may restrict or suspend a Market Participant's right to schedule or require the Market Participant to increase its Financial Security Amount if at any time such Market Participant's potential additional liability for Imbalance Energy and other ISO charges is determined by the ISO to be excessive by comparison with the likely cost of the amount of Energy scheduled by the Market Participant.

13 DISPUTE RESOLUTION.

13.1 Applicability.

13.1.1 General Applicability.

Except as limited below or otherwise as limited by law (including the rights of any party to file a complaint with FERC under the relevant provisions of the FPA), the ISO ADR Procedures shall apply to all disputes between parties which arise under the ISO Documents except where the decision of the ISO is stated in the provisions of this ISO Tariff to be final. The ISO ADR Procedures shall not apply to:

13.1.1.1 Disputes arising under contracts which pre-date the ISO Operations Date, except as the disputing parties may otherwise agree;

13.1.1.2 Disputes as to whether rates and charges set forth in this ISO Tariff are just and reasonable under the FPA.

13.1.2 Disputes Involving Government Agencies.

13.1.2.1 If a party to a dispute is a government agency the procedures herein which provide for the resolution of claims and arbitration of disputes are subject to any limitations imposed on the agency by law, including but not limited to the authority of the agency to effect a remedy. If the governmental agency is a federal entity, the procedures herein shall not apply to disputes involving issues arising under the United States Constitution.

13.1.3 Injunctive and Declaratory Relief.

Where the court having jurisdiction so determines, use of the ISO ADR Procedures shall not be a condition precedent to a court action for injunctive relief nor shall the provisions of California Code of Civil Procedures sections 1281 et seq. apply to such court actions.

19.3.3.3 Monthly Reports. On a monthly basis, the ISO shall publish on the ISO Website a report comparing the aggregated weekly peak Generation capacity to the weekly peak forecast Demand for the next month.

19.3.3.4 The ISO shall, on the basis of the information supplied by Participating Generators under Section 4.6.6.1 and other information available to the ISO, prepare and publish on WEnet forecast aggregate available Generation capacity and forecast Demand on an annual, quarterly and monthly basis. In publishing these forecasts, the ISO shall identify any expected Congestion conditions caused by planned Outages of Participating Generators.

20 CONFIDENTIALITY.

20.1 ISO.

The ISO shall maintain the confidentiality of all of the documents, data and information provided to it by any Market Participant that are treated as confidential or commercially sensitive under Section 20.2; provided, however, that the ISO need not keep confidential: (1) information that is explicitly subject to data exchange through WEnet pursuant to Section 6 of this ISO Tariff; (2) information that the ISO or the Market Participant providing the information is required to disclose pursuant to this ISO Tariff, or applicable regulatory requirements (provided that the ISO shall comply with any applicable limits on such disclosure); or (3) information that becomes available to the public on a non-confidential basis (other than as a result of the ISO's breach of this ISO Tariff).

20.2 Confidential Information.

The following information provided to the ISO by Scheduling Coordinators shall be treated by the ISO as confidential:

(a) individual bids for Supplemental Energy;

(b) individual Adjustment Bids for Congestion Management which are not designated by the Scheduling Coordinator as available;

(c) individual bids for Ancillary Services;

(d) transactions between Scheduling Coordinators;

(e) individual Generator Outage programs unless a Generator makes a change to its Generator Outage program which causes Congestion in the short term (i.e. one month or less), in which case, the ISO may publish the identity of that Generator.

(f) Demand Forecast and other hourly data provided by Scheduling Coordinators to the ISO pursuant to Section 31.1.4.

The following information provided to the ISO by Scheduling Coordinators or Market Participants for purposes of the Interim Reliability Requirements Program shall be treated by the ISO as confidential:

(a) Annual and monthly Resource Adequacy Plans pursuant to Sections 40.2.1 and 40.2.2, respectively, and Supply Plans pursuant to Section 40.6; however, any Planning Reserve Margin information required by Section 40.4 and any Qualifying Capacity eligibility criteria information required by Section 40.5.1 contained in the Resource Adequacy Plans and/or Supply Plans shall not be treated as confidential.

(b) Demand Forecast and other hourly data provided pursuant to Section 40.3.

(c) Information on existing import contracts, and any trades or sales of allocated import capacity, provided pursuant to Section 40.5.2.2.

(d) Information reported by non-Participating Generators pursuant to Sections 40.6A.3 and 40.7.3.

(e) Information submitted through the dispute or discrepancy resolution process pursuant to Section 40.2.3.

20.3 Other Parties.

No Market Participant shall have the right hereunder to receive from the ISO or to review any documents, data or other information of another Market Participant to the extent such documents, data or information is to be treated as in accordance with Section 20.2; provided, however, a Market Participant may receive and review any composite documents, data, and other information that may be developed based upon such confidential documents, data, or information, if the composite document does not disclose such

confidential data or information relating to an individual Market Participant and provided, however, that the ISO may disclose information as provided for in its bylaws.

20.4 Disclosure.

Notwithstanding anything in this Section 20 to the contrary,

(a) The ISO: (i) shall publish individual bids for Supplemental Energy, individual bids for Ancillary Services, and individual Adjustment Bids, provided that such data are published no sooner than six (6) months after the Trading Day with respect to which the bid or Adjustment Bid was submitted and in a manner that does not reveal the specific resource or the name of the Scheduling Coordinator submitting the bid or Adjustment Bid, but that allows the bidding behavior of individual, unidentified resources and Scheduling Coordinators to be tracked over time; and (ii) may publish data sets analyzed in any public report issued by the ISO or by the Market Surveillance Committee, provided that such data sets shall be published no sooner than six (6) months after the latest Trading Day to which data in the data set apply, and in a manner that does not reveal any specific resource or the name of any Scheduling Coordinator submitting bids or Adjustment Bids included in such data sets.

(b) If the ISO is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section 20, the ISO may disclose such information; provided, however, that as soon as the ISO learns of the disclosure requirement and prior to making such disclosure, the ISO shall notify any affected Market Participant of the requirement and the terms thereof. The Market Participant may, at its sole discretion and own cost, direct any challenge to or defense against the disclosure requirement and the ISO shall cooperate with such affected Market Participant to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The ISO shall cooperate with the affected Market Participant to obtain proprietary or confidential treatment of confidential information by the person to whom such information is disclosed prior to any such disclosure.

(c) The ISO may disclose confidential or commercially sensitive information, without notice to an affected Market Participant, in the following circumstances:

(i) If the FERC, or its staff, during the course of an investigation or otherwise, requests information that is confidential or commercially sensitive. In providing the information to FERC or its staff, the ISO shall take action consistent with 18 C.F.R. §§ 1b.20 and 388.112, and request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. The ISO shall provide the requested information to the FERC or its staff within the time provided for in the request for information. The ISO shall notify an affected Market Participant within a reasonable time after the ISO is notified by FERC or its staff that a request for disclosure of, or decision to disclose, the confidential or commercially sensitive information has been received, at which time the ISO and the affected Market Participant may respond before such information would be made public; or

(ii) In order to maintain reliable operation of the ISO Control Area, the ISO may share critical operating information, system models, and planning data with other WECC Reliability Coordinators, who have executed the Western Electricity Coordinating Council

Confidentiality Agreement for Electric System Data, or are subject to similar confidentiality requirements; or

(iii) In order to maintain reliable operation of the ISO Control Area, the ISO may share individual Generating Unit Outage information with the operations engineering and/or the outage coordination division(s) of other Control Area operators, Participating TOs, MSS Operators and other transmission system operators engaged in the operation and maintenance of the electric supply system whose system is significantly affected by the Generating Unit and who have executed the Western Electricity Coordinating Council Confidentiality Agreement for Electric System Data.

(d) Information submitted through Resource Adequacy Plans pursuant to Sections 40.2.1 and 40.2.2, Supply Plans pursuant to Section 40.6, and the dispute or discrepancy resolution process pursuant to Section 40.2.3 may be provided to:

(i) the Scheduling Coordinator(s) and/or Market Participant(s) involved in the dispute or discrepancy pursuant to Section 40.2.3, only to the limited extent necessary to identify the disputed transaction and relevant counterparty or counterparties.

(ii) the regulatory entity, whether the CPUC or a Local Regulatory Authority, with jurisdiction over a Load Serving Entity involved, pursuant to Section 40.2.3, in a dispute or discrepancy, or otherwise is identified by the ISO as exhibiting a potential deficiency in demonstrating compliance with Resource Adequacy rules adopted by the CPUC or Local Regulatory Authority, as applicable. The information provided shall be limited to the particular dispute, discrepancy or deficiency.

20.5 Confidentiality.

The ISO shall implement and maintain a system of communications with Scheduling Coordinators that includes the strict use of passwords for access to data to ensure compliance with Section 20. Access within the ISO to such data on ISO's communications systems, including databases and backup files, shall be strictly limited to authorized ISO personnel through the use of passwords and other appropriate means.

21 SCHEDULE VALIDATION TOLERANCES.

21.1 Temporary Simplification of Schedule Validation Tolerances.

Notwithstanding any other provision in the ISO Tariff, including the ISO Protocols, a Schedule shall be treated as a Balanced Schedule when aggregate Generation, adjusted for Transmission Losses, is within 20 MW of aggregate Demand, or such lower amount, greater than 1 MW, as may be established from time to time by the ISO. The ISO may establish the Schedule validation tolerance level at any time, between a range from 1 MW to 20 MW, by giving seven days' notice published on the ISO's "Home Page," at http://www.ISO.com or such other Internet address as the ISO may publish from time to time.

resulting increase in the total capability of the power plant;

(c) each existing Generating Unit connected to the ISO Controlled Grid that will be modified without increasing the total capability of the power plant but has changed the electrical characteristics of the power plant such that its re-energization may violate Applicable Reliability Criteria; and

(d) each existing qualifying facility Generating Unit connected to the ISO Controlled Grid whose total Generation was previously sold to a Participating TO or on-site customer but whose Generation, or any portion thereof, will now be sold in the wholesale market, subject to Section 25.1.2 below.

25.1.1 The owner of a Generating Unit described in Section 25.1 (a), (b), or (c), or its designee, shall be an Interconnection Customer required to submit an Interconnection Request and comply with the LGIP or ISO Tariff Appendix W, as applicable.

25.1.2 If the owner of a qualifying facility described in Section 25.1(d), or its designee, represents that the total capability and electrical characteristics of the qualifying facility will be substantially unchanged, then that entity must submit an affidavit to the ISO and the applicable Participating TO representing that the total capability and electrical characteristics of the qualifying facility will remain substantially unchanged. If there is any change to the total capability and electrical characteristics of the qualifying facility, however, the affidavit shall include supporting information describing any such changes. The ISO and the applicable Participating TO shall have the right to verify whether or not the total capability or electrical characteristics of the qualifying facility have changed or will change.

25.1.2.1 If the ISO and the applicable Participating TO confirm that the electrical characteristics are substantially unchanged, then that request will not be placed into the interconnection queue. However, the owner of the qualifying facility, or its designee, will be required to execute either a Standard Large Generator Interconnection Agreement in accordance with Section 11 of the LGIP or an interconnection agreement in accordance with ISO Tariff Appendix W, as applicable.

25.1.2.2 If the ISO and the applicable Participating TO cannot confirm that the total capability and electrical characteristics are and will be substantially unchanged, then the owner of the qualifying facility,

or its designee, shall be an Interconnection Customer required to submit an Interconnection Request and comply with either the LGIP or ISO Tariff Appendix W, as applicable.

25.2 Interconnections to the Distribution System.

Any proposed interconnection by the owner of a planned Generating Unit, or its designee, to connect that Generating Unit to a Distribution System of a Participating TO will be processed, as applicable, pursuant to the Wholesale Distribution Access Tariff or CPUC Rule 21, or other Local Regulatory Authority requirements, if applicable, of the Participating TO; provided, however, that the owner of the planned Generating Unit, or its designee, shall be required to mitigate any adverse impact on reliability of the ISO Controlled Grid consistent with the Standard Large Generator Interconnection Procedures. In addition, each Participating TO will provide to the ISO a copy of the system impact study used to determine the impact of a planned Generating Unit on the Distribution System and the ISO Controlled Grid pursuant to a request to interconnect under the applicable Wholesale Distribution Access Tariff or CPUC Rule 21, or other Local Regulatory Authority requirements, if applicable.

25.3 Maintenance of Encumbrances.

No new Generating Unit shall adversely affect the ability of the applicable Participating TO to honor its Encumbrances existing as of the time an Interconnection Customer submits its Interconnection Request to the ISO. The applicable Participating TO, in consultation with the ISO, shall identify any such adverse effect on its Encumbrances in the Interconnection System Impact Study performed under Section 7 of the LGIP or under Section 5.1 of ISO Tariff Appendix W, as applicable. To the extent the applicable Participating TO determines that the connection of the new Generating Unit will have an adverse effect on Encumbrances, the Interconnection Customer shall mitigate such adverse effect.

26 TRANSMISSION RATES AND CHARGES.

26.1 Access Charges.

All Market Participants withdrawing Energy from the ISO Controlled Grid shall pay Access Charges in accordance with this Section 26.1 and Appendix F, Schedule 3, except as provided in SPP 4.1. Prior to

the transition date determined under Section 4 of Schedule 3 to Appendix F, the Access Charge for each

Participating TO shall be

26.1.4 Wheeling.

Any Scheduling Coordinator or other such entity scheduling a Wheeling transaction shall pay to the ISO the product of (i) the applicable Wheeling Access Charge, and (ii) the total hourly schedules of Wheeling in kilowatt-hours for each month at each Scheduling Point associated with that transaction, except as provided in SPP 4.1. Schedules that include Wheeling transactions shall be subject to the Congestion Management procedures and protocols in accordance with Sections 27.1.1 and 27.1.2.

26.1.4.1 Wheeling Access Charge.

The Wheeling Access Charge shall be determined by the TAC Area and transmission ownership or Entitlement, less all Encumbrances, associated with the Scheduling Point at which the Energy exits the ISO Controlled Grid. The Wheeling Access Charge for Scheduling Points contained within a single TAC Area, that are not joint facilities, shall be equal to the High Voltage Access Charge for the applicable TAC Area in accordance with Section 3 of Appendix F plus the applicable Low Voltage Access Charge if the Scheduling Point is on a Low Voltage Transmission Facility. 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.

26.1.4.2 Wheeling Over Joint Facilities.

To the extent that more than one Participating TO owns or has Entitlement to transmission capacity, less all Encumbrances, exiting the ISO Controlled Grid at a Scheduling Point, the Scheduling Coordinator shall pay the ISO each month a rate for Wheeling at that Scheduling Point which reflects an average of the Wheeling Access Charge applicable to those Participating TOs, weighted by the relative share of such ownership or Entitlement to transmission capacity, less all Encumbrances, at such Scheduling Point. If the Scheduling Point is located at High Voltage Transmission Facilities, the Wheeling Access Charge will consist of a High Voltage Wheeling Access Charge component. Additionally, if the Scheduling Point is located at Low Voltage Transmission Facilities, the applicable Low Voltage Wheeling Access Charge component will be added to the Wheeling Access Charge. The methodology for developing the weighted average rate for Wheeling at each Scheduling Point is set forth in Appendix H.

26.1.4.3 Disbursement of Wheeling Revenues.

The ISO shall collect and pay to Participating TOs and other entities as provided in Section 24.7.3 all Wheeling revenues at the same time as other ISO charges and payments are settled. The ISO shall provide to the applicable Participating TO and other entities as provided in Section 24.7.3 a statement of the aggregate amount of Energy delivered to each Scheduling Coordinator using such Participating TO's Scheduling Point to allow for calculation of Wheeling revenue and auditing of disbursements. Wheeling revenues shall be disbursed by the ISO based on the following:

26.1.4.3.1 Scheduling Point with All Participating TOs in the Same TAC Area.

With respect to revenues received for the payment of High Voltage Wheeling Access Charges for Wheeling to a Scheduling Point at which all of the facilities and Entitlements, less all Encumbrances, are owned by Participating TOs in the same TAC Area, Wheeling revenues shall be disbursed to each such Participating TO based on the ratio of each Participating TO's High Voltage Transmission Revenue Requirement to the sum of all such Participating TO's High Voltage Transmission Revenue Requirements. If the Scheduling Point is located at a Low Voltage Facility, revenues received with respect to Low Voltage Wheeling Access Charges for Wheeling to that Scheduling Point shall be disbursed to the Participating TOs that own facilities and Entitlements making up the Scheduling Point in proportion to their Low Voltage Transmission Revenue Requirements. Additionally, if a Participating TO has a transmission upgrade or addition that was funded by a Project Sponsor, the Wheeling revenue allocated to such Participating TO shall be disbursed as provided in Section 24.7.3.

26.1.4.3.2 Scheduling Point without All Participating TOs in the Same TAC Area.

With respect to revenues received for the payment of Wheeling Access Charges for Wheeling to a Scheduling Point at which the facilities and Entitlements, less all Encumbrances, are owned by Participating TOs in different TAC Areas, Wheeling revenues shall be disbursed to such Participating TOs as follows. First, the revenues shall be allocated between such TAC Areas in proportion to the ownership and Entitlements of transmission capacity, less all Encumbrances, at the Scheduling Point of the Participating TOs in each such TAC Area. Second, the revenues thus allocated to each TAC Area shall be disbursed among the Participating TOs in the TAC Area in accordance with Section 26.1.4.3.1.

If a Generating Unit shut down according to this Section 27.1.1.6.1 cannot start up in time to meet its next day's Energy Schedules, the ISO shall charge the Scheduling Coordinator for that Generating Unit the lesser of the decremental reference price or the Market Clearing Price at the operating level set forth in the relevant Energy Schedule for any deviation from the next day's Final Day-Ahead Schedules for Energy caused by such shut-down. Charges set forth in this Section 27.1.1.6.1 shall not apply to (1) Reliability Must-Run Units operating solely under their Reliability Must-Run Contracts or (2) units operating during a Waiver Denial Period in accordance with the must-offer obligation.

The ISO shall apply the decremental reference prices to thermal Generating Units and to non-thermal Generating Units. If a Generating Unit is instructed by the ISO to shut down to manage Intra-Zonal Congestion, and is subsequently re-started, the Owner of that Generating Unit may invoice the ISO for the lesser of (1) the Start-Up Costs incurred and (2) the costs of keeping the Generating Unit warm to meet its Energy Schedules as set forth in Section 40.12.6. If the ISO Dispatches System Resources or Dispatchable Loads to alleviate Intra-Zonal Congestion, the ISO shall Dispatch those resources in merit order according to the resource's Day-Ahead or Hour-Ahead Adjustment Bid or Imbalance Energy bid.

The ISO shall only Redispatch Regulatory Must-Take or Regulatory Must-Run Generation, Intermittent Resources, or Qualifying Facilities to manage Intra-Zonal Congestion after Redispatching all other available and effective generating resources, including Reliability Must-Run Units.

27.1.1.6.1.1 Decremental Bid Reference Levels. Decremental bid reference levels shall be determined for use in managing Intra-Zonal Congestion as set forth above in Section 27.1.1.6.1.

(a) Determination. Decremental bid reference levels shall be determined by applying the following steps in order as needed:

1. Excluding proxy bids, mitigated bids, and bids used out of merit order for managing Intra-Zonal Congestion, the accepted decremental bid, or the lower of the mean or the median of a resource's accepted decremental bids if such a resource has more than one accepted decremental bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for daily changes in fuel prices using gas price 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

Edison Company, or Pacific Gas and Electric Company), or, if the resource is not served from one of those three Service Areas, from the nearest of those three Service Areas. There will be a six-day time lag between when the gas price used in the daily gas index is determined and when the daily gas index based on that gas price can be calculated. For the purposes of this Section 27.1.1.6.1, to determine whether accepted decremental bids over the previous 90 days were accepted during competitive periods, the independent entity responsible for determining reference prices will apply a test to the prior 90-day period. The test will require that the ratio of a unit's accepted out-of-sequence decremental bids (MWh) for the prior 90 days to its total accepted decremental bids (MWh) for the prior 90 days be less than 50 percent. If this ratio is greater or equal to 50%, accepted decremental bids will be determined to have been accepted in non-competitive periods and cannot be used to determine the decremental reference price. This test would be applied each day on a rolling 90-day basis. One ratio would be calculated for each unit with no differentiation for various output segments on the unit. Accepted and justified decremental bids below the applicable soft cap, as set forth in Section 39.3 of this Tariff, will be included in the calculation of reference prices;

2. A level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined, and provided the Market Participant has provided sufficient data in accordance with specifications provided by the independent entity responsible for determining reference prices;

3. 90 percent of the unit's default Energy Bid determined monthly as set forth in Section 40.7.5 (based on the incremental heat rate submitted to the independent entity responsible for determining reference prices, adjusted for gas prices, determined according to paragraph (a)(1) above, and the variable O&M cost on file with the independent entity responsible for determining reference prices, or the default O&M cost of $6/MWh);

4. 90 percent of the mean of the economic Market Clearing Prices for the units' relevant location during the lowest-priced 25 percent of the hours that the unit was dispatched or scheduled over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices determined according to paragraph (a)(1) above; or

Scheduling Coordinators shall not submit any Schedule using a transmission path for any Settlement Period for which the Operating Transfer Capability for that path is zero MW. The ISO shall reject Schedules submitted for transmission paths on which the Operating Transfer Capability is zero MW. If the Operating Transfer Capability of a transmission path is reduced to zero after Final Day-Ahead Schedules have been submitted, then, if time permits, the ISO shall direct the responsible Scheduling Coordinators to reduce all Schedules on such zero-rated transmission paths to zero in the Hour-Ahead Market. As necessary to comply with Applicable Reliability Criteria, the ISO shall reduce any non-zero Final Hour-Ahead Schedules across zero-rated transmission paths to zero after the close of the Hour-Ahead Market. No Usage Charges will be assessed, nor will any Usage Charges for counter-flow be paid, for Schedules across a path with an Operating Transfer Capability of zero.

30.3.5A No Scheduling Coordinator shall submit a Circular Schedule. The ISO may periodically provide examples of such Circular Schedules under the ISO Home Page.

30.4 Verification of Information.

The ISO shall be entitled to take all reasonable measures to verify that Scheduling Coordinators meet the technical and financial criteria set forth in Section 4.5.1 hereof and the accuracy of information submitted to the ISO pursuant to Section 30.2.

30.4.1 Validation of Balanced Schedules.

Each Scheduling Coordinator will be assigned a workspace within the ISO's scheduling system. Each workspace will have a work area for Day-Ahead and Hour-Ahead Schedules, Adjustment Bids and Supplemental Energy bids. The Scheduling Coordinator shall only be allowed to access and manipulate its Schedule and bid data within this workspace. Each area is organized into segments. A segment is used to hold the Scheduling Coordinator's Schedules relating to the same Trading Day. The Schedule validation process is divided into two stages. The ISO shall carry out the first stage validation immediately after it has received a Schedule. The ISO shall carry out the second stage validation ten (10) minutes before (pre-validation) and immediately after each deadline (as specified in the Scheduling Protocol) for submission of Schedules. However, a Scheduling Coordinator can also initiate the stage two validation at any time prior to that deadline, as described in more detail in the Scheduling Protocol. If

the Scheduling Coordinator adds a new Schedule or modifies an existing Schedule, that Schedule must be re-validated. Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Balanced Schedules.

30.4.1.1 Stage One Validation.

During stage one validation, each incoming Schedule will be validated to verify proper content, format and syntax. The ISO will check that the Scheduling Coordinator had not exceeded its Aggregate Credit Limit and verify that the Scheduling Coordinator is certified in accordance with the ISO Tariff. The ISO will further verify that the Scheduling Coordinator has inputted valid Generating Unit and Demand location identification. Scheduled Reliability Must-Run Generation will be verified against the contract reference numbers in the ISO's Scheduling Coordinator database. A technical validation will be performed verifying that a scheduled Generating Unit's output is not beyond it's declared capacity and/or operating limits. If there is an error found during stage one validation, the Scheduling Coordinator will be notified immediately through WEnet. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit the Schedule if it is still within the ISO's timing requirements. Additionally, if the ISO detects an invalid contract usage (of either Existing Contract rights or Firm Transmission Rights), the ISO will issue an error message in similar manner to the Scheduling Coordinator and allow the Scheduling Coordinator to view the message(s), to make changes, and to resubmit the contract usage template(s) if it is still within the ISO's timing requirements. The Scheduling Coordinator is also notified of successful validation via WEnet.

30.4.1.2 Stage Two Validation.

During stage two validation, Schedules will be checked to determine whether each Scheduling Coordinator's aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) equals the Scheduling Coordinator's aggregate Demand Forecast, including external exports. The Scheduling Coordinator must take into account the applicable Generation Meter Multipliers (GMMs). The Scheduling Coordinator will be notified if the counterpart trade to any Inter-Scheduling Coordinator Ancillary Service Trade has not been submitted, or is infeasible (i.e., if both Scheduling Coordinators are selling or both are buying).

be derived pursuant to Section 40.8.4.

For Curtailable Demand, the submitted Minimum Load Cost ($/hr) is the cost incurred while operating the resource at reduced consumption after receiving a Dispatch Instruction. The submitted Minimum Load Cost must not be negative.

30.5 [Not Used]

30.6 RMR.

30.6.1 Procurement of Reliability Must-Run Generation by the ISO.

30.6A.1 A Reliability Must-Run Contract is a contract entered into by the ISO with a Generator which operates a Generating Unit giving the ISO the right to call on the Generator to generate Energy and, only as provided in this Section 30.6.1, or as needed for Black Start or Voltage Support required to meet local reliability needs, or to procure Ancillary Services from Potrero or Hunter's Point power plants to meet operating criteria associated with the San Francisco local reliability area, to provide Ancillary Services from the Generating Units as and when this is required to ensure that the reliability of the ISO Controlled Grid is maintained.

30.6A.1.1 If the ISO, pursuant to Section 8.5.4(e), has elected to procure an amount of megawatts of its forecast needs for an Ancillary Service in the Hour-Ahead Markets and there is not an adequate amount of capacity bid into an Hour-Ahead Market for the ISO to procure such amount of megawatts of that Ancillary Service (excluding bids that exceed price caps imposed by the ISO or FERC), the ISO may call upon Reliability Must-Run Units under Must-Run Contracts to meet the remaining portion of that amount of megawatts for that Ancillary Service but only after accepting all available bids in the Hour-Ahead Market (including any unused bids that can be used to satisfy that particular Ancillary Services requirement under Section 8.2.3.6), except that the ISO shall not be required to accept bids that exceed price caps imposed by the ISO or the FERC.

30.6A.1.2 If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day –

(1) the ISO determines that it requires more of an Ancillary Service than it has procured;

(2) all additional Day-Ahead bids for that Ancillary Service that have not been withdrawn (including any unused bids that can be used to satisfy that particular Ancillary Services requirement under Section 8.2.3.6) have been selected pursuant to Section 8.7, except that the ISO shall not be required to accept bids that exceed price caps imposed by the ISO or the FERC;

(3) the ISO has notified Scheduling Coordinators of the circumstances existing in paragraphs (1) and (2) of this Section 30.6A.1.2; and

(4) after such notice, the ISO determines that a Bid Insufficiency condition exists in the Hour-Ahead Market for the Settlement Period in which the ISO requires more of an Ancillary Service;

the ISO may call upon Reliability Must-Run Units under Reliability Must-Run Contracts to meet the additional needs in addition to any amounts that the ISO has called upon under Section 30.6A.1.1. The ISO must provide the notice specified in paragraph (3) of this Section 30.6A.1.2 as soon as possible after the ISO determines that additional Ancillary Services are needed for which bids are not available. The ISO may only determine that a Bid Insufficiency exists in the Hour-Ahead Market after the close of the Hour-Ahead Market, unless an earlier determination is required in order to accommodate the Reliability Must-Run Unit's operating constraints. For the purposes of this Section, a Bid Insufficiency exists in an Hour-Ahead Market if, and only if –

(a) bids in the Hour-Ahead Market for the particular Ancillary Service (including any unused bids that can be used to satisfy that particular Ancillary Services requirement under Section 8.2.3.6) that remain after first procuring the megawatts of the Ancillary Service that the ISO had notified Scheduling Coordinators it would procure in the Hour-Ahead Market pursuant to Section 8.5.4 ("remaining Ancillary Service requirement") represent, in the aggregate, less than two times such remaining Ancillary Service requirement; or

(b) there are less than two unaffiliated bidders to provide such remaining Ancillary Service requirement.

If a Bid Insufficiency condition exists, the ISO may nonetheless accept available market bids if it determines in its sole discretion that the prices bid and the supply curve created by the bids indicate that

Adjustment Bids for the RMR Unit, the Adjustment Bid shall specify the RMR Market Energy as the minimum MW output to which the Applicable RMR Scheduling Coordinator will allow the RMR Unit to be redispatched for that hour.

31.1.3.3 Whether or not the RMR Energy is in a Final Schedule, the Applicable RMR Owner must deliver the RMR Energy pursuant to the RMR Dispatch Notice. If the RMR Owner has bid and scheduled the RMR Energy as required by this Section 31, any RMR Energy provided but not included in the Final Schedule will be paid as Uninstructed Imbalance Energy. Notwithstanding anything to the contrary in the RMR Contract, neither the Applicable RMR Owner nor the Applicable RMR Scheduling Coordinator shall be entitled to any payment from any source for RMR Market Energy that is not bid and scheduled as required by this Section 31.

31.1.3.4 If, at any time after 5:00 a.m. on the day before the Trading Day, the ISO determines that it requires additional Energy from specific Reliability Must-Run Units during the Trading Day, the ISO will notify Scheduling Coordinators for such Reliability Must-Run Units of the amount and time of the additional Energy requirements from such Reliability Must-Run Units (the "Supplemental RMR Dispatch Notice"). If the owner of the RMR Unit or the Applicable RMR Scheduling Coordinator for the RMR Unit specified in the Supplemental RMR Dispatch Notice has not already notified the ISO of a payment option for any hour of the Trading Day included in the Supplemental Dispatch Notice at the time the Supplemental Dispatch Notice is issued, the RMR Owner shall do so no later than three hours before the hour specified in the Supplemental RMR Dispatch Notice for each such hour that is at least four hours after the issuance of the Supplemental Dispatch Notice. If the RMR Owner elects to provide the Energy requested in the Supplemental RMR Dispatch Notice as RMR Contract Energy, the Scheduling Coordinator shall 1) submit an Hour-Ahead Energy Schedule that includes all or part of the RMR Contract Energy requested in the Supplemental RMR Dispatch Notice in a bilateral transaction to Demand or in an Inter-Scheduling Coordinator Energy Trade and 2) submit an Hour-Ahead Energy Schedule for all RMR Contract Energy requested in the Supplemental RMR Dispatch Notice not Scheduled in a bilateral transaction as a Schedule to the RMR Contract Energy Load Point and balance that Schedule by also Scheduling an additional quantity of Demand equal to the remaining amount of RMR Contract Energy at the RMR Contract Energy Load Point. The RMR Contract Energy Load Point shall be used solely for the

purpose of balancing the RMR Contract Energy not otherwise Scheduled to forecast Demand or through an Inter-Scheduling Coordinator Energy Trade. The price for the RMR Contract Energy Scheduled to the RMR Contract Energy Load Point shall be the price paid to Demand deviations from Final Hour-Ahead Schedules.

31.1.3.5 [Not Used]

31.1.4 Demand Information.

31.1.4.1 Daily Information. By 10:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator shall provide to the ISO a Demand Forecast specified by UDC Service Area for which it will schedule deliveries for each of the Settlement Periods of the following Trading Day. The ISO shall aggregate the Demand information by UDC Service Area and transmit the aggregate Demand information to each UDC serving such aggregate Demand.

31.1.4.2 Preliminary Weekly Information. Each Scheduling Coordinator shall provide to the ISO, no later than seven (7) days after the end of each week, which shall end at Sunday HE 24, data for the previous week (Monday through Sunday), in electronic format, comparing, for each hour of that week: (1) the Scheduling Coordinator's total Day-Ahead scheduled Demand by UDC Service Area, as submitted pursuant to Section 4.5.4.2, (2) the Scheduling Coordinator's total Day-Ahead Demand Forecast by UDC Service Area, as submitted pursuant to Section 31.1.4.1, and (3) an estimate of the Scheduling Coordinator's actual Demand by UDC Service Area. The requirements of this section do not apply to the portion of a Scheduling Coordinator's Demand associated with Station Power.

31.1.5 The Preferred Schedule of each Scheduling Coordinator for the following Trading Day shall be submitted at or prior to 10:00 a.m. on the day preceding the Trading Day together with any Adjustment Bids and Ancillary Services bids.

31.1.6 In submitting its Preferred Schedule, each Scheduling Coordinator shall notify the ISO of any Dispatchable Loads which are not scheduled but have submitted Adjustment Bids and are available for Dispatch at those same Adjustment Bids to assist in relieving Congestion.

31.1.7 ISO Analysis of Preferred Schedules.

On receipt of the Preferred Schedules, the ISO will analyze the Preferred Schedules of Applicable RMR

33.1.2.1 Preferred Schedules Become Final Hour-Ahead Schedules.

If the ISO identifies no Congestion on the ISO Controlled Grid, the Preferred Schedules shall become Final Hour-Ahead Schedules and the ISO shall notify Scheduling Coordinators accordingly.

33.1.2.2 Congestion Management Provisions for Final Hour-Ahead Schedules.

If the ISO identifies Congestion, it shall use the Congestion Management provisions of Section 27.1.1 of this ISO Tariff to develop the Final Hour-Ahead Schedules.

33.1.2.3 Final Hour-Ahead Schedules.

The ISO shall inform each Scheduling Coordinator of its responsibilities to provide Ancillary Services in accordance with Section 8.7. Not later than thirty (30) minutes before the commencement of each Settlement Period, the ISO shall provide each Scheduling Coordinator with the Final Schedule for that Settlement Period. Each Final Schedule shall be a Balanced Schedule and shall contain the following information:

33.1.2.3.1 Generation.

33.1.2.3.1.1 Name and identification number of each Participating Generator appearing in the Final Schedule;

33.1.2.3.1.2 Location Code of each Generating Unit, System Resource and Scheduling Point;

33.1.2.3.1.3 The changes in the final scheduled quantity (in MWh) for each such Generating Unit, System Resource and scheduled voltage;

33.1.2.3.1.4 Notification if the scheduled Generation was adjusted to resolve Congestion; and

33.1.2.3.1.5 [Not Used]

33.1.2.3.2 Load.

33.1.2.3.2.1 For each Load where a Demand Bid has been submitted, the Location Code of the Take-Out Point;

33.1.2.3.2.2 Final Scheduled Quantity. Final scheduled quantity (in MWh) of Demand; and

33.1.2.3.2.3 Notification of Adjustment. Notification if the scheduled Demand was adjusted to resolve Congestion.

33.1.2.4 Usage Charges. The ISO shall notify each Scheduling Coordinator of the applicable Usage Charge calculated in accordance with Section 27.1.2.

34 REAL-TIME.

34.1 Energy Bids.

34.1.1 Energy Bid Definition.

A single Energy Bid curve per resource per hour shall be used in: (a) the real-time Hourly Pre-Dispatch as set forth in Section 34.3.0.2, and (b) Dispatch in the Real Time Markets. A corresponding operational ramp rate as provided for in Section 30.4.6 shall be submitted along with the single Energy Bid curve and shall be used in determination of Dispatch Instructions pursuant to Section 34.3.1(c).

The Energy Bid shall be a staircase price ($/MWh) versus quantity (MW) curve of up to 10 segments. The Energy Bid shall be submitted to the real-time Imbalance Energy market using the Supplemental Energy Bid template. The Energy Bid curve shall be monotonically increasing, i.e., the price of a subsequent segment shall be greater than the price of a previous segment. Subject to the foregoing, sellers may increase or decrease bids in the ISO Real Time Market for capacity associated with those parts of the bid curve that were not accepted in or before the Hour-Ahead Market. For capacity associated with those parts of the bid curve previously accepted in or before the Hour-Ahead Market, sellers may only submit lower bids in subsequent markets. Each Forbidden Operating Region must be represented by only one bid segment.

34.1.2 Energy Bid Submission.

34.1.2.1 Real Time Market.

Bids shall be submitted for use in the real-time Hourly Pre-Dispatch Section 34.3.0.2(i) and the Real-Time Economic Dispatch up to sixty-two (62) minutes prior to the Operating Hour. Resources required to offer their Available Generation in accordance with Section 40.7.4 shall be required to submit Energy Bids for

1) all of their Available Generation and 2) any Ancillary Services capacity awarded or self-provided in the Day-Ahead or Hour-Ahead Ancillary Services markets. In the absence of submitted bids, default bids will be used for resources required to offer their Available Generation in accordance with Section 40.7.4. Resources not required to offer their Available Generation in accordance with Section 40.7.4 that were awarded or self-provided Ancillary Services capacity must submit an Energy Bid for no less than the amount of awarded or self-provided Ancillary Services capacity. Resources not required to offer their Available Generation in accordance with Section 40.7.4 may voluntarily submit Energy Bids. Submitted Energy Bids shall be subject to the Damage Control Bid Cap as set forth in Section 39.1 and to the Mitigation Measures set forth in Attachment A to Appendix P.

34.1.2.2 Real-Time Energy Bid Partition.

The portion of the single Energy Bid that corresponds to the high end of the resource's operating range, shall be allocated to any awarded or self-provided Ancillary Services in the following order from higher to lower capacity: (a) Regulation Up; (b) Spinning Reserve; (c) Non-Spinning Reserve; and (d) Replacement Reserve. For resources providing Regulation Up, the upper regulating limit shall be used if it is lower than the highest operating limit. The remaining portion of the Energy Bid (i.e. that portion not associated with capacity committed to provide Ancillary Services) shall constitute a Bid to provide Supplemental Energy.

34.1.2.3 Creation of the Real-Time Merit Order Stack.

34.1.2.3.1 Sources of Imbalance Energy.

The following Energy Bids will be considered in the creation of the real-time merit order stack for Imbalance Energy:

(a) Supplemental Energy Bids;

(b) Ancillary Services Energy Bids (except for Regulation) submitted for specific Ancillary Services for those resources which have been selected in the ISO's Ancillary Services auction to supply such specific Ancillary Services; and

(c) Ancillary Services Energy Bids (except for Regulation) submitted for specific Ancillary Services

for those resources which Scheduling Coordinators have elected to use to self-provide such specific Ancillary Services and for which the ISO has accepted such self-provision.

34.1.2.3.2 Stacking of the Energy Bids.

The sources of Imbalance Energy described in Section 34.1.2.3.1 will be arranged in order of increasing Energy Bid prices to create a merit order stack. This merit order stack will be arranged without regard to the source of the Energy Bid except that Energy Bids associated with Spinning and Non-Spinning Reserve shall not be included in the merit order stack during normal operating conditions if the capacity associated with such bids has been designated as available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency. In the event of an unplanned Outage, a Contingency or threatened or actual System Emergency, all Energy Bids associated with Spinning and Non-Spinning Reserve may be included in the merit order stack. In the event of Inter-Zonal Congestion, separate merit order stacks will be created for each Zone. The information in the merit order stack shall be provided to the real-time dispatcher through the RTD Software. Where, in any Settlement Interval, the highest decremental Energy Bid in the merit order stack is higher than the lowest incremental Energy Bid, the RTD Software will eliminate the Price Overlap by actually dispatching for all those incremental and decremental bids which fall within the overlap.

References to incremental Energy Bids include references to Demand reduction bids, and for the purpose of applying this algorithm a reduction in Demand shall be treated as an equivalent increase in Generation.

34.1.2.3.3 Use of the Merit Order Stack.

The merit order stack, as described in Section 34.1.2.3.2, can be used to supply Energy for:

(a) satisfying needs for Imbalance Energy (differences between actual and scheduled Generation, Demand and external imports/exports) in real time;

(b) managing Inter-Zonal Congestion in real time;

(c) supplying Energy necessary to allow resources providing Regulation service to return to the base point of their regulating ranges in real time;

(d) recovering Operating Reserves utilized in real time;

(e) procuring additional Voltage Support required from resources beyond their power factor ranges in real time; and

(f) Dispatching System Resources and Dispatchable Loads and increasing Generating Units' output to manage Intra-Zonal Congestion in real time.

34.1.3 Requirement to Submit Energy Bids For Awarded or Self-Provided Ancillary Services Capacity.

Scheduling Coordinators for resources that have been awarded or self-provide Regulation Up, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity must submit a Supplemental Energy bid for at least all the awarded or self-provided Ancillary Services capacity. To the extent a Supplemental Energy bid is not so submitted for a gas-fired resource, the ISO shall calculate a Supplemental Energy bid in accordance with Section 40.10.1 and insert that bid into the real-time Imbalance Energy market. To the extent a Supplemental Energy bid is not so submitted for a non-gas-fired resource, the ISO shall insert a bid of $0/MWh into the real-time Imbalance Energy market.

34.2 Supplemental Energy Bids.

In addition to the Generating Units, Loads and System Resources which have been scheduled to provide Ancillary Services in the Day-Ahead and Hour-Ahead Markets, the ISO may Dispatch Generating Units, Loads or System Resources for which Scheduling Coordinators have submitted Supplemental Energy bids. Supplemental Energy bids are available to the ISO for procurement and use for Imbalance Energy, additional Voltage Support and Congestion Management in the Real Time Market.

34.2.1 Identification of Supplemental Energy Bids.

The upper portion of a Scheduling Coordinator's Energy Bid for a resource providing Spinning, Non-Spinning, or Replacement Reserves that corresponds to the resource's available capacity up to the highest operating limit, shall be allocated to any awarded or self-provided Ancillary Services in the following order from higher to lower capacity: a) Regulation Up; b) Spinning Reserve; c) Non-Spinning Reserve; and d) Replacement Reserve. For resources providing Regulation Up, the upper regulating limit

shall be used if it is lower than the highest operating limit. The remaining portion of the Energy Bid, if there is any, shall constitute Supplemental Energy.

34.2.1.1 Timing of Supplemental Energy Bids.

Supplemental Energy bids must be submitted to the ISO no later than sixty-two (62) minutes prior to the operating hour. Bids may also be submitted at any time after the Day-Ahead Market closes. These Supplemental Energy bids cannot be withdrawn after sixty-two (62) minutes prior to the Settlement Period. A System Resource that identifies its bid as a Hourly Pre-Dispatch bid will only be pre-dispatched and will not be subject to any intra-hour Redispatch except as necessary to maintain inter-Control Area transmission reliability.

34.2.1.1A Form of Supplemental Energy Bid Information.

Supplemental Energy bids must include the following information:

34.2.1.2 Generation Section of Energy Bid Data.

Each Scheduling Coordinator offering Spinning, Non-Spinning, or Replacement Reserve, or Supplemental Energy to the ISO will submit the following information for each Generating Unit for each Settlement Period

(a) Scheduling Coordinator's ID code;

(b) name of Generating Unit;

(c) Generating Unit operating limits (high and low MW);

(d) Generating Unit operational ramp rate in MW/minute;

(e) Generating Unit startup time function in minutes;

(f) Generating Unit startup cost function in $/start;

(g) Generating Unit Minimum Load Cost in $/hr; and

(h) the MW and $/MWh values for each Generating Unit for which a Supplemental Energy bid is being submitted consistent with this ISO Tariff.

Analysis pursuant to Section 38.2 and Appendix P.1 reveal a significant possibility of the presence of or potential for exercises of market power that would adversely affect the operation of the ISO Markets, or other markets interconnected or interdependent on the ISO Markets, the Department of Market Analysis shall take the appropriate measures under this section and under Appendix P to institute the corrective action most effective and appropriate for the situation or, in the case of markets interconnected to or interdependent on the ISO Markets, the Department of Market Analysis may recommend corrective actions to the appropriate regulatory agencies.

38.4.2 Further Actions.

Where the monitoring activities of or any consequent investigations carried out by the Department of Market Analysis pursuant to Sections 38.2 and 38.3 reveal that activities or behavior of Market Participants in the ISO Markets have the effect of, or potential for, undermining the efficiency, workability or reliability of the ISO Markets to give or to serve such Market Participants an unfair competitive advantage over other Market Participants, the Department of Market Analysis shall fully investigate and analyze the effect of such activities or behavior and make recommendations to the ISO CEO and the ISO Governing Board for further action by the ISO or, where necessary, by other entities. The Department of Market Analysis may, where appropriate, make specific recommendations to the ISO CEO and to the ISO Governing Board for amendment to rules and protocols under its control, or for changes to the structure of the ISO Markets, and the Department of Market Analysis may recommend actions, including fines or suspensions, against specific entities in order to deter such activities or behavior.

38.4.3 Adverse Effects of Transition Mechanisms.

Should the monitoring and analysis conducted under Appendix P reveal significant adverse effects of transition mechanisms on competition in or the efficient operation of the ISO Markets, the Department of Market Analysis shall examine and fully assess the efficacy of all possible measures that may be taken by the ISO, in order to prevent or to mitigate such adverse effects. The Department of Market Analysis shall make such recommendations to the CEO of the ISO and to the ISO Governing Board as it considers appropriate for action by the ISO and/or for referral to regulatory or law enforcement agencies. Such proposed measures may include, but shall not be limited to the following:

38.4.3.1 the use of direct bid caps as a mechanism to prevent or mitigate artificially high Market Clearing Prices caused by abuses of market power;

38.4.3.2 the use of contracts for differences for eliminating the incentive for Generators to bid ISO prices to artificially high levels enabled by the presence of market power;

38.4.3.3 calling upon Reliability Must-Run Units to operate; and to modify Reliability Must-Run Contracts;

38.4.3.4 bid floors to prevent or mitigate the possible exercise of below-cost bidding or predatory pricing.

In the event that the ISO Governing Board adopts, and where necessary obtains regulatory approval for, any measure proposed pursuant to Section 38.4.3, the Department of Market Analysis shall monitor the implementation and effect of such measure on the state of the ISO Markets and shall periodically report on them to the CEO and the ISO Governing Board.

39 RULES LIMITING CERTAIN ENERGY AND ANCILLARY SERVICE BIDS.

39.1 Damage Control Bid Cap.

Notwithstanding any other provision of this ISO Tariff, Damage Control Bid Cap provisions of Sections 39.2 and 39.3 shall apply to the ISO's Energy and Ancillary Service capacity markets.

39.2 Maximum Bid Level.

The maximum bid level in the ISO's Energy markets shall be $400/MWh. Market Participants may submit bids in the ISO's Energy markets above $400/MWh, however, any accepted bids above this cap are not eligible to set the Market Clearing Price and are subject to cost-justification and refund.

The maximum bid level applicable to Adjustment Bids used in the ISO's Congestion Management markets shall be $400/MWh, and the ISO shall not accept Adjustment Bids in excess of that bid level.

The maximum bid level in the ISO's Ancillary Service capacity markets shall be $400/MWh. Market Participants may submit bids in the ISO's Ancillary Serivce capacity markets above $400/MWh, however, any accepted bids above this cap are not eligible to set the Market Clearing Price and are subject to cost-

justification and refund.

39.3 Negative Decremental Energy Bids.

Negative decremental Energy bids into the ISO Markets less than -$30/MWh (minus thirty dollars per MWh) shall not be eligible to set any Market Clearing Price and, if Dispatched, shall be paid as bid. If the ISO Dispatches a bid below -$30/MWh, the supplier must submit a detailed breakdown of the component costs justifying the bid to the ISO and to the Federal Energy Regulatory Commission no later than seven (7) days after the end of the month in which the bid was submitted. The ISO will treat such information as confidential and will apply the procedures in Section 20.4 of this ISO Tariff with regard to requests for disclosure of such information. The ISO shall pay suppliers for amounts in excess of $-30/MWh after those amounts have been justified.

ARTICLE V – RESOURCE ADEQUACY

40 RESOURCE ADEQUACY.

40.1 Must-Offer Obligations.

This Section 40 applies to all Scheduling Coordinators representing Load Serving Entities serving retail Load within the ISO Control Area. For purposes of this Section 40 of the ISO Tariff, Load Serving Entity

is defined as: (1) any entity serving retail Load under the jurisdiction of the California Public Utilities Commission (hereinafter "CPUC"), including an Electrical corporation under section 218 of the California Public Utilities Code (hereinafter "PUC"), an Electric service provider under section 218.3 of the PUC, and a Community choice aggregator under section 331.1 of the PUC (hereinafter collectively "CPUC Load Serving Entities"); and (2) all entities serving retail Load in the ISO Control Area not within the jurisdiction of the CPUC including: (i) a local publicly owned electric utility under section 9604 of the PUC; (ii) the State Water Resources Development System commonly known as the State Water Project; and (iii) any Federal entities, including but not limited to Federal Power Marketing Authorities, that serve retail Load (hereafter collectively "non-CPUC Load Serving Entities"). Load Serving Entity shall not include customer generation located on the customer's site or providing electric service through arrangements authorized by Section 218 of the PUC, if the customer generation, or the Load it serves, meets one of the following criteria: (i) it takes standby service from the electrical corporation on a commission-approved rate schedule that provides for adequate backup planning and operating reserves for the standby customer class; (ii) it is not physically interconnected to the electric transmission or distribution grid, so that if the customer generation fails, backup electricity is not supplied from the electricity grid; or (iii) there is physical assurance that the Load served by the customer generation will be curtailed concurrently and commensurately with an outage of the customer generation.

40.2 Submission of Annual and Monthly Resource Adequacy Plan.

40.2.1 Annual Resource Adequacy Plan.

Each Scheduling Coordinator for a Load Serving Entity serving Load within the ISO Control Area must provide the ISO with an annual Resource Adequacy Plan; however, Scheduling Coordinators representing a Load Serving Entity with an MSS Agreement shall submit the information required by this section pursuant to the terms and formal standards set forth in the MSS Agreement. The annual Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area shall be submitted on the schedule and in the form approved by the CPUC. The annual Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the non-CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area, except Load Serving Entities with an MSS Agreement, shall be submitted no later than October 25th of each year and in the form set forth on the ISO Website. Other than for good cause, the form of the Resource Adequacy Plan and the date for submission for the CPUC Load Serving Entities and the Non-CPUC Load Serving Entities should be identical. The annual Resource Adequacy Plan must identify the Resource Adequacy Resources that will be relied upon to satisfy the Planning Reserve Margin under Section 40.4, or portion thereof as established by the CPUC or applicable Local Regulatory Authority, and must apply the Net Qualifying Capacity requirements of Section 40.5.2.

40.2.2 Monthly Resource Adequacy Plan.

Each Scheduling Coordinator for a Load Serving Entity serving Load within the ISO Control Area must provide the ISO with a monthly Resource Adequacy Plan; however, (1) Scheduling Coordinators representing a Load Serving Entity with an MSS Agreement shall submit the information required by this section pursuant to the terms and formal standards set forth in the MSS Agreement and (2) Scheduling Coordinators for a Load Serving Entity serving Load within the ISO Control Area in a forecasted peak amount of less than (1) MW on average per day over the compliance year may notify the ISO that the Load Serving Entity's annual Resource Adequacy Plan pursuant to Section 40.2.1 will constitute its monthly Resource Adequacy Plan under this section for each month of the following compliance year.

The monthly Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area shall be submitted on the schedule and in the form approved by the CPUC. The monthly Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the non-CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area, except for Load Serving Entities with an MSS Agreement, shall be submitted no later than on the last business day of the second month prior to the compliance month (e.g., March 31 for May) and in the form set forth on the ISO's Website. Other than for good cause, the form of the Resource Adequacy Plan and the date for submission for the CPUC Load Serving Entities and the Non-CPUC Load Serving Entities should be identical. The monthly Resource Adequacy Plan must identify the Resource Adequacy Resources that will be relied upon to satisfy the Planning Reserve Margin under Section 40.4 for the relevant reporting month and must apply the Net Qualifying Capacity requirements of Section 40.5.2.

40.2.3 Resource Adequacy Plan Compliance.

The ISO will evaluate whether each monthly Resource Adequacy Plan submitted by a Scheduling Coordinator on behalf of a Load Serving Entity serving Load within the ISO Control Area satisfies the Load Serving Entity's obligation to procure sufficient Net Qualifying Capacity to comply with its Planning Reserve Margin under Section 40.4. If a Scheduling Coordinator for a Load Serving Entity submits a Resource Adequacy Plan that the ISO identifies as not demonstrating compliance with Resource Adequacy rules adopted by the CPUC or other Local Regulatory Authority, as applicable, the ISO will, within 10 business days, first notify the relevant Scheduling Coordinator, or in the case of a mismatch between Resource Adequacy Plan(s) and Supply Plan(s), the relevant Scheduling Coordinators in an attempt to resolve the issue. If this process does not resolve the ISO's concern, the ISO will notify the CPUC or other appropriate Local Regulatory Authority of the potential deficiency. To the extent that the CPUC or other appropriate Local Regulatory Authority allows Load Serving Entities under its jurisdiction to cure the identified deficiency or determines that no deficiency exists, the Scheduling Coordinator shall inform the ISO at least 10 days before the effective month. If the deficiency is not resolved prior to the 10th day before the effective month, the ISO will use the information contained in the Supply Plan to set

Resource Adequacy Resources' obligations under this section of the ISO Tariff for the applicable reporting month.

40.2.4 Reporting of Enforcement Actions.

To the extent that the CPUC or other Local Regulatory Authority has not adopted rules allowing public access to records or information regarding action taken for violations of its Resource Adequacy policies and rules, the Scheduling Coordinator for each Load Serving Entity serving Load in the ISO Control Area notified of a potential failure to comply by the ISO and not resolved under 40.2.3 must report to the ISO within thirty (30) days of any action taken by the appropriate Local Regulatory Authority in response to the deficiency notification.

40.2.5 Compliance with Submission Obligation.

Scheduling Coordinators representing Load Serving Entities Serving Load in the ISO Control Area that fail to provide the ISO with annual or monthly Resource Adequacy Plans as set forth in this ISO Tariff shall be subject to Section 37.6.1 of the ISO Tariff.

40.3 Demand Forecasts.

The annual and monthly Resource Adequacy Plan must include a Demand Forecast as follows:

a. For CPUC Load Serving Entities, the Demand Forecast shall be the Demand Forecast required by the CPUC. To the extent the ISO has not received a CPUC Load Serving Entity's load forecast through the CPUC's Resource Adequacy process, the Scheduling Coordinators for the CPUC Load Serving Entities must provide to the ISO a copy of the Demand Forecast that they provided to the CPUC and CEC, subject to the confidentiality terms established by the CPUC in its proceeding.

b. For non-CPUC Load Serving Entities, the Demand Forecast shall be the Demand Forecast required by the applicable Local Regulatory Authority. Scheduling Coordinators for non-CPUC Load Serving Entities must provide data and/or supporting information, as requested by the ISO, for the Demand Forecasts required by this Section for each represented non-CPUC Load Serving Entity.

c. If the CPUC or other Local Regulatory Authority has not established a requirement to prepare a Demand Forecast, the Scheduling Coordinator for the Load Serving Entity shall prepare and provide the ISO with a Demand Forecast that shall be the Load Serving Entity's monthly non-coincident peak Demand Forecast for its Service Area, for its MSS area, or in each Service Area of an Original Participating TO in which the Load Serving Entity serves Load, unless the Load Serving Entity agrees to utilize a coincident peak determination provided by the California Energy Commission for such Load Serving Entity. Scheduling Coordinators for Load Serving Entities covered by this subsection must provide data and/or supporting information, as requested by the ISO, for the Demand Forecasts required by this Section for each represented Load Serving Entity.

For Load Serving Entities that are local publicly owned electric utilities as defined in Section 9604 of the PUC, the Demand Forecasts required by this Section 40.3 should be consistent with Section 9620(a) of the PUC, as it may be amended from time to time, requiring that such Load Serving Entities meet their

Planning Reserve Margin, peak demand, and operating reserves.

40.4 Planning Reserve Margin.

The monthly Resource Adequacy Plan must include a level of Resource Adequacy Capacity sufficient to meet 100% of the Demand Forecast in Section 40.3 plus a Planning Reserve Margin as follows:

a. For Scheduling Coordinators representing CPUC Load Serving Entities, the Planning Reserve Margin shall be that adopted by the CPUC.

b. For Scheduling Coordinators representing non-CPUC Load Serving Entities, the Planning Reserve Margin shall be that adopted by the appropriate Local Regulatory Authority.

c. For Scheduling Coordinators representing Load Serving Entities for which the CPUC or other Local Regulatory Authority has not established a Planning Reserve Margin as of May 31, 2006, the Planning Reserve Margin shall be: (1) for compliance months June through September 2006, the Planning Reserve Margin provided by the Load Serving Entity to accommodate any processes to approve the Planning Reserve Margin that may be pending before the applicable Local Regulatory Authority and (2) thereafter, no less than 115% of the peak hour of the month in the Demand Forecast set forth in Section 40.3.

40.5 Determination of Resource Adequacy Capacity.

Resource Adequacy Capacity shall be the quantity of capacity in MWs from a resource listed in a Resource Adequacy Plan. Resource Adequacy Capacity cannot exceed a resource's Net Qualifying Capacity.

40.5.1 Qualifying Capacity.

Qualifying Capacity is the capacity from a resource prior to application of the Net Capacity provisions of Section 40.5.2. The criteria for determining the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types may be established by the CPUC or other applicable Local Regulatory Authority and provided to the ISO. For

compliance months June through September 2006, the criteria for determining the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types may be provided by the Load Serving Entity to accommodate any processes to approve the Qualifying Capacity criteria that may be pending before the applicable Local Regulatory Authority. Only if such criteria are not provided by the CPUC or other Local Regulatory Authority by August 31, 2006 for compliance month October 2006, then Section 40.13 will apply. The ISO shall use the criteria provided by the CPUC, other Local Regulatory Authority or, if necessary, Section 40.13, to determine and verify, if necessary, the Qualifying Capacity of all resources listed in a Resource Adequacy Plan; however, to the extent a resource is listed by one or more Scheduling Coordinators in their respective Resource Adequacy Plans, which apply the criteria of more than one regulatory entity that leads to conflicting Qualifying Capacity values for that resource, the ISO will apply the respective Qualifying Capacity formulas applicable for each Load Serving Entity.

40.5.2 Net Qualifying Capacity.

Net Qualifying Capacity is Qualifying Capacity, determined under the criteria provided by the CPUC or other Local Regulatory Authority or, if such criteria is not provided by the CPUC or Local Regulatory Authority, under Section 40.13 of this ISO Tariff, reduced, as applicable, based on: (1) testing and verification or (2) deliverability restrictions. The Net Qualifying Capacity determination shall be made by the ISO pursuant to the provisions of this ISO Tariff. The ISO shall produce a report, posted to the ISO Website and updated from time to time, setting forth the Net Qualifying Capacity of Participating Generators. All other resources may be included in the report under this Section upon their request. Any disputes as to the ISO's determination regarding Net Qualifying Capacity shall be subject to the ISO's alternative dispute resolution procedures.

40.5.2.1 Deliverability Within the ISO Control Area.

In order to determine Net Qualifying Capacity from a Generating Unit, the ISO will determine that the Generating Unit is able to serve the aggregate of Load by means of a deliverability analysis. The deliverability analysis will be performed annually and shall focus on peak Demand conditions. The ISO will review its input assumptions and draft results with Market Participants before completing its determination. The ISO will coordinate with the CPUC and other Local Regulatory Authorities so that the results of the deliverability analysis can be incorporated in annual and monthly Resource Adequacy Plans. The results of the ISO's 2006 deliverability analysis shall be effective for a period no shorter than compliance year 2007. To the extent the deliverability analysis shows that the Qualifying Capacity of a Generating Unit is not deliverable to the aggregate of Load under the conditions studied, the Qualifying Capacity of the Generating Unit will be reduced on a MW basis for the capacity that is undeliverable.

40.5.2.2 Deliverability of Imports.

This Section 40.5.2.2 shall apply only to Resource Adequacy Plans covering the period through December 31, 2007, unless superseded earlier by alternative ISO Tariff provisions. Total import capacity will be assigned to Load Serving Entities serving Load in the ISO Control Area and other Market Participants, if applicable, for 2007 as described by the following sequence of steps.

1. Step 1: The ISO shall establish for 2007 for each branch group the total import capacity values for the ISO Control Area, and will post those values on the ISO Website by July 1, 2006.

2. Step 2: For each branch group, the total capacity established in Step 1 will be reduced by subtracting the import capacity associated with (i) Existing Transmission and (ii) encumbrances and transmission ownership rights. Existing Contracts and encumbrances and transmission ownership rights therefore shall be reserved for holders of such commitments as part of the deliverability study and will not be subject to allocation under this Section.

3. Step 3: From the amount of import capacity remaining on each branch group determined in Step 2 above, Load Serving Entities serving Load within the ISO Control Area will receive, to the extent feasible, an allocation on a particular branch group selected by the Load Serving Entity equal to each entity's resource commitments from outside the ISO Control Area, as of March 10, 2006, the terms of which runs through at least calendar year 2007. The branch group shall be selected by the Load Serving Entity based on the primary branch group upon which the energy or capacity from the particular resource commitment from outside the ISO Control Area has been historically scheduled or, for a resource commitment without a scheduling history, the primary branch group upon which the energy or capacity from the particular resource commitment from outside the ISO Control Area is anticipated to be scheduled. To the extent a particular branch group is over requested, such that the MWs represented in all requested resource commitments utilizing the branch group exceed the branch group's remaining import capacity, the requested resource commitment MW quantities will be allocated available capacity based on the "Import Capacity Load Share" ratio of each Load Serving Entity submitting such resource commitments. To the extent this initial allocation has not fully assigned the total import capacity of a particular branch

group to the requested resource commitments, the remaining capacity will be allocated until fully exhausted based on the Import Capacity Load Share ratio of each Load Serving Entity whose submitted resource commitment has not been fully satisfied.

a. Import Capacity Load Share is each Load Serving Entity's proportionate share of the forecasted 2007 coincident peak Load for the ISO Control Area relative to the total coincident peak Load of all Load Serving Entities that have not had their request for import capacity for a resource commitment on a particular branch group fully satisfied. The proportionate share of the forecasted 2007 peak Load for the ISO Control Area for each Load Serving Entity is the "Coincident Load Share," as determined by the California Energy Commission.

b. The ISO will notify the Scheduling Coordinator for each Load Serving Entity of the Load Serving Entity's Coincident Load Share. The ISO will further notify the Scheduling Coordinator for each Load Serving Entity of the amount of, and branch group on which, import capacity has been allocated to the Load Serving Entity pursuant to this Step 3. The import capacity allocated pursuant to this Step 3 shall be referred to as "Commitment Import Capacity."

4. Step 4: To the extent import capacity remains unallocated following Steps 1-3 above, the ISO will publish on its Website remaining aggregate import capacity, the identity of the branch groups with available capacity, and the MW quantity remaining on each such branch group. The remaining aggregate import capacity will be allocated to Load Serving Entities serving Load within the ISO Control Area through their Scheduling Coordinators based on each Load Serving Entity's Coincident Load Share. The quantity of import capacity allocated to a Load Serving Entity under this paragraph is that entity's "Remainder Import Capacity." This Step 4 does not allocate import capacity on a specific branch group, but rather allocates aggregate import capacity.

5. Step 5: Load Serving Entities shall be allowed to trade some or all of their Remainder Import Capacity or Commitment Import Capacity to any other Load Serving Entity or Market Participant during a period of time established by ISO Market Notice. The ISO will accept trades among

LSEs and Market Participants only to the extent such trades are reported to the ISO in a manner established by ISO Market Notice.

6. Step 6: Three business days after the close of the trading period set forth in Step 5 above, the Scheduling Coordinator for each Load Serving Entity or Market Participant shall notify the ISO of its request to allocate its post-trading Remainder Import Capacity on a MW per available branch group basis. The ISO will honor the requests to the extent a branch group has not been over requested. If a branch group is over requested, the requests for Remainder Import Capacity on that branch group will be allocated based on the ratio of each Load Serving Entity's Import Capacity Load Share, as used in Step 3. A Market Participant without a Coincident Load Share will be assigned the Coincident Load Share equal to the average Coincident Load Share of those Load Serving Entities from which it received Remainder Import Capacity. The ISO will notify each Scheduling Coordinator for Load Serving Entities or Market Participants of their accepted allocation under this Step 6.

7. Step 7: Following Step 6, the ISO will publish on its Website remaining aggregate import capacity, if any, the identity of the branch groups with available capacity, and the MW quantity remaining on each such branch group. To the extent import capacity remains unallocated, in the time period and manner established by ISO Market Notice, all Load Serving Entities or Market Participants shall notify the ISO of their requests to allocate any remaining Remainder Import Capacity on a MW per available branch group basis. The ISO will honor the requests to the extent a branch group has not been over requested. If a branch group is over requested, the requests on that branch group will be allocated based on the ratio of each Load Serving Entity or Market Participant's Import Capacity Load Share, as used in Steps 3 and 6. The ISO will notify each Scheduling Coordinator for a Load Serving Entity or Market Participant of the Load Serving Entity or Market Participant's accepted allocation under this Step 7. No further iterations will be permitted.

This multi-step allocation of total import capacity does not guarantee or result in any actual transmission service being allocated and is only used for determining the maximum import capacity that can be

credited towards satisfying the Planning Reserve Margin of a Load Serving Entity under this Section 40. Upon the request of the ISO, Scheduling Coordinators must provide the ISO with information on existing import contracts and any trades or sales of their load share allocation. To the extent that the ISO's review of Resource Adequacy Plans identifies reliance upon imports that exceed the import capacity allocated to the Load Serving Entity under this section, the ISO will inform the CPUC or appropriate Local Regulatory Authority of any Resource Adequacy Plan submitted by a Scheduling Coordinator for a Load Serving Entity under their respective jurisdiction that exceeds its allocation of import capacity.

40.6 Submission of Supply Plans.

Scheduling Coordinators representing Resource Adequacy Resources supplying Resource Adequacy Capacity shall provide the ISO with annual and monthly Supply Plans; however, Scheduling Coordinators for resources listed on schedule 14 of an MSS Agreement need not submit a Supply Plan, unless any capacity from such Schedule 14 resources has been sold to any Load Serving Entity other than the MSS Operator that owns or controls the resource. The annual Supply Plan shall be provided by September 30th of each year. The monthly Supply Plan shall be provided on the last business day of the second month prior to the compliance month (e.g., March 31 for May). Both the annual and monthly Supply Plans shall be provided in the form set forth on the ISO's Website, listing their commitments to provide Resource Adequacy Capacity to any Load Serving Entity or Entities for the reporting period.

40.6.1 Compliance with Supply Plan Obligation.

Scheduling Coordinators representing Resource Adequacy Resources supplying Resource Adequacy Capacity that fail to provide the ISO with annual or monthly Supply Plans as set forth in this ISO Tariff shall be subject to Section 37.6.1 of the ISO Tariff.

40.6A Availability of Resource Adequacy Resources.

40.6A.1 Applicability.

The requirements of Section 40.6A shall apply to all Resource Adequacy Resources identified on the Resource Adequacy Plans submitted by Scheduling Coordinators for Load Serving Entities serving Load in the ISO Control Area other than Resource Adequacy Resources identified exclusively on the Resource Adequacy Plans of (i) Load Serving Entities that have entered into a Metered Subsystem Agreement with the ISO and (ii) the State Water Project.

40.6A.2 Available Generation.

For the purposes of Section 40.6A, a Resource Adequacy Resources' "Available Generation" shall be: (a) the Resource Adequacy Capacity of a Generating Unit, other than a Hydroelectric facility or a QF that is still under a power purchase agreement with a host utility, System Unit that has contracted to supply Resource Adequacy Capacity to a non-MSS Load Serving Entity serving Load with the ISO Control Area, adjusted for any outages or reductions in capacity reported to the ISO in accordance with this ISO Tariff, (b) minus the unit's scheduled operating level as identified in the ISO's Final Hour-Ahead Schedule, (c) minus the unit's capacity committed to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator, and (d) minus the capacity of the unit committed to deliver Energy or provide Operating Reserve to the Resource Adequacy Resources' Generator's Native Load.

In the case where the Resource Adequacy Resource is a System Resource, and to the extent the CPUC or other Local Regulatory Authority has imposed an obligation that System Resources relied upon by Load Serving Entities within their jurisdiction to meet Resource Adequacy requirements must be available to the ISO, the Available Generation of the System Resource shall be the Resource Adequacy Capacity of the System Resource adjusted for any outages or reductions in capacity reported to the ISO in accordance with this ISO Tariff, (b) minus the total amount of the System Resource's actual energy scheduled on the specific intertie of the import Resource Adequacy Capacity as identified in the ISO's Final Hour-Ahead Schedules, and (c) minus the amount of the System Resource's commitments on the

specific intertie of the import Resource Adequacy Capacity to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator. The Available Generation of the System Resource shall never be less than zero.

40.6A.3 Reporting Requirements for Non-Participating Generators.

So that the ISO may determine the Available Generation of Resource Adequacy Resources, Resource Adequacy Resources, other than non-resource specific System Resources and Qualifying Facilities ("QFs") with effective contracts under the Public Utilities Regulatory Policies Act, that are not Participating Generators shall be required to file with the ISO: (i) the Generating Unit's minimum operating level; (ii) the Generating Unit's maximum operating level; and (iii) the Generating Unit's ramp rates at all operating levels; and (iv) such other information the ISO determines is necessary to determine available generation and to dispatch Resource Adequacy Resources. In addition, Resource Adequacy Resources that are not Participating Generators must, consistent with the notification obligations of Participating Generators and in order to comply with the intent of this Section 40.6A, notify the ISO, as soon as practicable, of any Planned Maintenance Outages, Forced Outages, Force Majeure Event outages or any other reductions in their maximum operating levels or Resource Adequacy Capacity during the relevant month.

40.6A.4 Obligation to Offer Available Capacity.

Except as set forth in Sections 40.6A.5 and 40.6A.6, all Resource Adequacy Resources shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 40.6A.2 and any other Available Generation beyond its Resource Adequacy Capacity shall be subject to the FERC must-offer obligation as set forth in Section 40.7. The Resource Adequacy Resource shall make available to the ISO Real Time Market all Resource Adequacy Capacity that is not subject to an outage or is otherwise participating in the ISO Market or included on a self-schedule. Notwithstanding the foregoing, a Resource Adequacy Resource that is a Participating Intermittent Resource satisfies its obligation to offer Available Generation under this Section by scheduling in accordance with Appendix Q of the ISO Tariff.

40.6A.5 Submission of Bids and Applicability of the Proxy Price.

For each Operating Hour, the Scheduling Coordinator for the Resource Adequacy Resource shall submit Supplemental Energy bids for all of their Available Generation to the ISO in accordance with Section 34.2. In addition, the ISO shall calculate for each gas-fired Resource Adequacy Resource (other than gas-fired Resource Adequacy Resources which are also System Resources), in accordance with Section 40.10.1, a Proxy Price for Energy.

If a Scheduling Coordinator for the Resource Adequacy Resource fails to submit a Supplemental Energy bid for any portion of its Available Generation for any Dispatch Interval, the un-bid quantity of the Resource Adequacy Resource's Available Generation will be deemed by the ISO to be bid at the Resource Adequacy Resource's Proxy Price if (i) the Resource Adequacy Resource is a gas-fired Generating Unit and (ii) the Resource Adequacy Resource has provided the ISO with adequate data in compliance with Section 40.6A.3 for the applicable Generating Unit. For all other Resource Adequacy Resources that are Generating Units, the un-bid quantity of the Resource Adequacy Resources' Available Generation will be deemed by the ISO to be bid and settled in accordance with Section 11.2. In order to dispatch resources providing Imbalance Energy in proper merit order the ISO will insert this un-bid quantity into the Resource Adequacy Resource's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the Resource Adequacy Resources' Available Generation.

40.6A.6 Resource Adequacy Resource Obligation Process.

Resource Adequacy Resources may seek a waiver of the obligation to offer all Available Generation, as set forth in Section 40.6A.4 of this ISO Tariff, for one or more of their units. All Resource Adequacy Resources obligated under their respective Resource Adequacy Plans that have not submitted Day-Ahead Energy Schedules will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all Available Generation. If conditions permit, the ISO may, at its sole discretion, grant waivers and allow a Resource Adequacy Resource to remove one or more Generating Units from service and, in doing so, the ISO will first grant waivers to FERC Must-Offer Generators, on a non-discriminatory basis, that are not also Resource Adequacy Resources, and then, if permissible, the ISO may grant waivers to Resource Adequacy Resources on a non-discriminatory basis.

The hours for which waivers are not granted shall constitute Waiver Denial Periods. A Waiver Denial Period shall be extended as necessary to accommodate the unit minimum up and down times. Units shall be on-line in real time during Waiver Denial Periods, or they will be in violation of the availability. Exceptions shall be allowed for verified forced outages or as otherwise set forth in Section 40.6A.5. The ISO may revoke waivers as necessary due to outages, changes in Load forecasts, or changes in system conditions. The ISO shall determine which waiver(s) will be revoked, and shall notify the relevant Scheduling Coordinator(s). The ISO shall inform a Resource Adequacy Resource that its Waiver request has been approved, disapproved or revoked, and shall provide the Resource Adequacy Resource with the reason(s) for the decision, which reasons shall be non-discriminatory apart from the status of whether the unit is a Resource Adequacy Resource. The ISO will: (1) notify Resource Adequacy Resources of the ISO decisions on pending Waiver requests received no later than 10:00 a.m. (beginning of Hour Ending 11) no later than 11:30 a.m. (middle of Hour Ending 12) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 11:30 a.m. on the following day, notify Resource

Adequacy Resources of the ISO decisions on Waiver requests that were submitted to the ISO after 10:00 a.m. (beginning of Hour Ending 11) on the day before; (3) end Waiver Denial Periods at any time; (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to the time a unit would be required to be on-line generating at its Pmin; and (5) revoke a waiver denial for a Short-Start Resource Adequacy Resource at any time and such revocation will be communicated via a ISO real-time dispatch or unit commitment instruction.

40.6A.7 Penalties for Non-Compliance.

In addition to any other penalty or settlement consequence of a failure of a unit to operate in accordance with a ISO operating order, the failure of a Scheduling Coordinator for a Resource Adequacy Resource to make the Resource Adequacy Resource available to the ISO in accordance with the requirements of Section 40 of this ISO Tariff or to operate the Resource Adequacy Resource by placing it online or in a manner consistent with a submitted Supplemental Energy bid or Proxy Price Energy Bid shall result in that Scheduling Coordinator being subject to the sanctions set forth in Section 37.2 of the ISO Tariff.

40.6B Recovery of Minimum Load Costs By Resource Adequacy Resources.

40.6B.1 Eligibility.

Except as set forth below, Resource Adequacy Resources that are Generating Units and System Units for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity shall be eligible to recover Un-Recovered Minimum Load Costs during Waiver Denial Periods. Units from Resource Adequacy Resources that incur Minimum Load Costs during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a Resource Adequacy Resource has a Final Hour-Ahead Energy Schedule, the Resource Adequacy Resource shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a Resource Adequacy Resource generating at minimum load in compliance with the supply obligation, produces a quantity of Energy that varies from its minimum operating level by more than the Tolerance Band, the Resource Adequacy Resource shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a Resource Adequacy Resource produces a quantity of

Energy above minimum load due to an ISO Dispatch Instruction, the Resource Adequacy Resource shall recover its Un-Recovered Minimum Load Costs as set forth in this Section and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible Resource Adequacy Resource for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from Resource Adequacy Resources that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) To the extent the Instructed Imbalance Energy payments are not sufficient to cover the generator's Minimum Load Cost as defined in Section 40.6B.3 of this ISO Tariff, the generator will also receive an uplift payment for its Un-Recovered Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the unit runs at minimum load in compliance with the Resource Adequacy offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

40.6B.2 Payments for Imbalance Energy above the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.

When, on a Settlement Interval basis, a Resource Adequacy Resource's Generating Unit or System Units for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity produces a quantity of Energy above the unit's minimum operating level due to an ISO Dispatch Instruction, the Resource Adequacy Resource shall recover Un-Recovered Minimum Load Costs as set forth in Section 40.6B.1 and its bid costs, based on the ISO's instruction, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band.

40.6B.3 Payments for Imbalance Energy for the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.

Resource Adequacy Resources operating at or near its operating level during a Waiver Denial Period either: (1) without a forward Schedule for its minimum operating level Energy or (2) with a Schedule to a special-purpose Demand ID for the sole purpose of Scheduling the minimum operating level Energy shall be paid its Un-Recovered Minimum Load Costs subject to eligibility as set forth in Section 40.6B.1 and not be paid an additional amount by the ISO for Energy actually delivered.

40.6B.4 Un-Recovered Minimum Load Costs.

The Un-Recovered Minimum Load Costs for each hour of Waiver Denial Period shall be calculated as the difference between: (1) a resource's Minimum Load Costs as calculated in this Section for the same Settlement Interval and (2) the Imbalance Energy payment for a resource's minimum load energy in the Settlement Interval. If the Imbalance Energy payment for minimum load energy exceeds the Minimum Load Costs, then there are no Un-Recovered Minimum Load Costs. The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: (1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 40.10) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC and the gas price 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 Resource Adequacy Resource is not served from one of those three Service Areas; and (2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.

40.6B.5 Allocation of Un-Recovered Minimum Load Costs.

For each Settlement Interval, the ISO shall determine that the Un-Recovered Minimum Load Costs for

Resource Adequacy Resources, as applicable, for each unit operating during a Waiver Denial Period are due to (1) local reliability requirements, (2) zonal requirements, or (3) Control Area-wide requirements. For each such month, the ISO shall sum the Un-Recovered Minimum Load Costs and shall allocate those costs as follows:

(1) if the Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity was operating to meet local reliability requirements, the incremental locational cost shall be allocated to the Participating TO in whose PTO Service Territory the unit is located, or, where the unit is located outside the PTO Service Territory of any Participating TO, to the Participating TO or Participating TOs whose PTO Service Territory or Territories are contiguous to the Service Area in which the Generating Unit or System Unit is located, in proportion to the benefits that each such Participating TO receives, as determined by the ISO. Where the costs allocated under this section are allocated to two or more Participating TOs, the ISO shall file the allocation under Section 205 of the Federal Power Act. For the purposes of this section, the incremental locational cost shall be the additional costs associated with committing and operating a particular unit or units to meet a local reliability requirement over the costs of a less expensive unit or units that would have been committed and operated absent the local reliability requirement. If a unit is committed in real-time for local reliability, its Un-Recovered Minimum Load costs shall be considered incremental locational costs. Costs allocated under this part (1) shall be considered Reliability Services Costs.

(2) if the Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity was operating due to Inter-Zonal Congestion, the Un-Recovered Minimum Load Costs shall be allocated on a monthly basis to each Scheduling Coordinator in the constrained Zone based on the ratio of that Scheduling Coordinator’s monthly Demand to the sum of all Scheduling Coordinator’s monthly Demand in that Zone;

(3) if the Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity was operating to satisfy an ISO Control Area-wide need, the ISO shall allocate the Un-Recovered Minimum Load Costs in the following way:

a. first, to the monthly absolute total of all Net Negative Uninstructed Deviation (determined for each Settlement Interval based on Final Hour-Ahead Schedules) at a per-MWh rate that shall not exceed a figure that is determined by dividing the total Un-Recovered Minimum Load Cost in that month by the sum of the minimum loads for Generating Units operating under Waiver Denial Periods in that month;

b. finally, all remaining costs not allocated per (a) shall be allocated to each Scheduling Coordinator in proportion to the sum of that Scheduling Coordinator's monthly Control Area Gross Load and Demand within California outside the ISO Control Area that is served by exports to the monthly sum of the ISO Control Area Gross Load and the projected Demand within California outside the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators.

40.6B.6 Payment of Available Capacity under the Resource Adequacy Obligation.

Available Generation of Resource Adequacy Resources that is required to be offered to the Real Time Market, if dispatched by the ISO, shall be settled as follows: the actual amount of the dispatched Energy shall be settled at the applicable Instructed Imbalance Energy Market Clearing Price. Un-Recovered Minimum Load Cost compensation shall be paid for all otherwise eligible hours within the Waiver Denial Period that the unit generated above minimum load in compliance with ISO Dispatch Instructions.

40.7 FERC Must-Offer Obligations.

40.7.1 Applicability.

The requirements of Section 40.7 shall apply to (a) all Participating Generators, and (b) all persons,

regardless of whether the person is a "public utility" as defined in Section 201 of the Federal Power Act, that own or control one or more non-hydroelectric Generating Units or System Units or System Resources located in California from which energy or capacity is either: (i) sold through any market operated by the ISO, or (ii) transmitted over the ISO Controlled Grid. Each person described in this Section 40.7.1 is referred to in the ISO Tariff as a "FERC Must-Offer Generator." The requirements of this Section 40.7 shall apply to all non-hydroelectric Generating Units located in California that are owned or controlled by a FERC Must-Offer Generator.

40.7.2 Available Generation.

For the purposes of Section 40.7, a FERC Must-Offer Generator's "Available Generation" from a non-hydroelectric Generating Unit shall be: (a) the Generating Unit's maximum operating level adjusted for any outages or reductions in capacity reported to the ISO in accordance with Section 9.3.9 or 40.7.3 and for any limitations on the Generating Unit's operation under applicable law, including contractual obligations, which shall be reported to the ISO, (b) minus the Generating Unit's scheduled operating level as identified in the ISO's Final Hour-Ahead Schedule, (c) minus the Generating Unit's or System Unit's capacity committed to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator, and (d) minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the FERC Must-Offer Generator's Native Load.

40.7.3 Reporting Requirements for Non-Participating Generators.

So that the ISO may determine the Available Generation of all FERC Must-Offer Generators, FERC Must-Offer Generators that are not Participating Generators shall be required to file with the ISO, for each non-hydroelectric Generating Unit located in California they own or control: (i) the Generating Unit's minimum operating level; (ii) the Generating Unit's maximum operating level; and (iii) the Generating Unit's ramp rates at all operating levels; and (iv) such other information the ISO determines is necessary to determine available generation and to dispatch FERC Must-Offer Generators. In addition, FERC Must-Offer Generators that are not Participating Generators must, consistent with the notification obligations of Participating Generators and in order to comply with the intent of this Section 40.7, notify the ISO, as

soon as practicable, of any Planned Maintenance Outages, Forced Outages, Force Majeure Event outages or any other reductions in their maximum operating

levels or Resource Adequacy Capacity during the relevant month.

40.7.4 Obligation To Offer Available Generation.

Except as set forth in Sections 40.7.5 and 40.7.6, all FERC Must-Offer Generators shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 40.7.2.

40.7.5 Submission of Bids and Applicability of the Proxy Price.

For each Operating Hour, FERC Must-Offer Generators shall submit Supplemental Energy bids for all of their Available Generation to the ISO in accordance with Section 34.2. In addition, the ISO shall calculate for each gas-fired FERC Must-Offer Generator, in accordance with Section 40.10.1, a Proxy Price for Energy.

If a FERC Must-Offer Generator fails to submit a Supplemental Energy bid for any portion of its Available Generation for any Dispatch Interval, the unbid quantity of the FERC Must-Offer Generator's Available Generation will be deemed by the ISO to be bid at the FERC Must-Offer Generator's Proxy Price for that hour if: (i) the applicable Generating Unit is a gas-fired unit and (ii) the FERC Must-Offer Generator has provided the ISO with adequate data in compliance with Sections 40.7.7 and 40.7.3 for the applicable Generating Unit. For all other Generating Units owned or controlled by a FERC Must-Offer Generator, the unbid quantity of the FERC Must-Offer Generator's Available Generation will be deemed by the ISO to be bid and settled in accordance with Section 11.2. In order to dispatch resources providing Imbalance Energy in proper merit order, the ISO will insert this unbid quantity into the FERC Must-Offer Generator's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the FERC Must-Offer Generator's Available Generation.

40.7.6 FERC Must-Offer Obligation Process.

FERC Must-Offer Generators may seek a waiver of the obligation to offer all available capacity, as set forth in Section 40.7.4 of this ISO Tariff, for one or more of their Generating Units or System Units.

All FERC Must-Offer Generators obligated under the must-offer obligation that have not submitted Day-

Ahead Energy Schedules will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all Available Generation. If conditions permit, the ISO may, at its sole

discretion, grant waivers and allow a FERC Must-Offer Generator to remove one or more Generating Units or System Units from service. In doing so, the ISO will first grant waivers to FERC Must-Offer Generators, on a non-discriminatory basis, that are not also Resource Adequacy Resources and then, if permissible, the ISO may grant waivers to Resource Adequacy Resources on a non-discriminatory basis. The hours for which waivers are not granted shall constitute Waiver Denial Periods. A Waiver Denial Period shall be extended as necessary to accommodate Generating Unit minimum up and down times. Generating Units shall be on-line in real time during Waiver Denial Periods, or they will be in violation of the must-offer obligation. Exceptions shall be allowed for verified forced outages. The ISO may revoke waivers as necessary due to outages, changes in Load forecasts, or changes in system conditions. The ISO shall determine which waiver(s) will be revoked, and shall notify the relevant Scheduling Coordinator(s). To the extent conditions permit, the ISO will revoke the waivers of Resource Adequacy Resources prior to revoking the waivers of other FERC Must-Offer Generators. The ISO shall inform a FERC Must-Offer Generator that its Waiver request has been approved, disapproved or revoked, and shall provide the FERC Must-Offer Generator with the reason(s) for the decision, which reasons shall be non-discriminatory. The ISO will: (1) notify FERC Must-Offer Generators of the ISO decisions on pending Waiver requests received no later than 10:00 a.m. (beginning of Hour Ending 11) no later than 11:30 a.m. (middle of Hour Ending 12) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 11:30 a.m. on the following day, notify FERC Must-Offer Generators of the ISO decisions on Waiver requests that were submitted to the ISO after 10:00 a.m. (beginning of Hour Ending 11) on the day before; (3) end Waiver Denial Periods at any time; and (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to the time a unit would be required to be on-line generating at its Pmin.

40.8 Recovery of Minimum Load Costs By FERC Must-Offer Generators.

40.8.1 Eligibility.

Except as set forth below, Generating Units shall be eligible to recover Minimum Load Costs during Waiver Denial Periods. Units from FERC Must-Offer Generators that incur Minimum Load Costs during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such

hours. When a FERC Must-Offer Generator has a Final Hour-Ahead Energy Schedule, the FERC Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a FERC Must-Offer Generator generating at minimum operating level in compliance with the must-offer obligation, produces a quantity of Energy that varies from its minimum

operating level by more than the Tolerance Band, the FERC Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a FERC Must-Offer Generator's resource produces a quantity of Energy above minimum load due to an ISO Dispatch Instruction, the FERC Must-Offer Generator shall recover its Minimum Load Costs as set forth in this Section and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible FERC Must-Offer Generator for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from FERC Must-Offer Generators that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) The generator's Minimum Load Cost as defined in Section 40.8.4 of this ISO Tariff, the generator will also receive a payment for its Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the Generating Unit runs at minimum load in compliance with the must-offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

40.8.2 Payments for Imbalance Energy Above the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.

When, on a Settlement Interval basis, a FERC Must-Offer Generator's Generating Unit produces a quantity of Energy above the Generating Unit's minimum operating level due to an ISO Dispatch Instruction, the FERC Must-Offer Generator shall recover Minimum Load Costs and its bid costs, based on the ISO's instruction, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band.

40.8.3 Payments for Imbalance Energy for the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.

A Generating Unit operating at or near its minimum operating level during a Waiver Denial Period either (1) without a forward Schedule for its minimum operating level Energy or (2) with a Schedule to a special-purpose Demand ID for the sole purpose of Scheduling the minimum operating level Energy shall be paid, in addition to being paid its Minimum Load Costs subject to eligibility as set forth in Section 40.8.1, an amount equal to the Resource Specific Settlement Interval Ex Post Price times the amount of Energy actually delivered.

40.8.4 Minimum Load Costs.

The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: (1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 40.10) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC and the gas price 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 FERC Must-Offer Generator is not served from one of those three Service Areas; and (2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.

40.8.5 [Not Used]

40.8.6 Allocation of Minimum Load Costs.

For each Settlement Interval, the ISO shall determine that the Minimum Load Costs for each FERC Must Offer Generator unit operating during a Waiver Denial Period are due to (1) local reliability requirements, (2) zonal requirements, or (3) Control Area-wide requirements. For each such month, the ISO shall sum the Settlement Interval Minimum Load Costs and shall allocate those costs as follows:

(1) if the Generating Unit was operating to meet local reliability requirements, the incremental locational cost shall be allocated to the Participating TO in whose PTO Service Territory the Generating Unit is located, or, where the Generating Unit is located outside the PTO Service Territory of any Participating TO, to the Participating TO or Participating TOs whose PTO Service Territory or Territories are contiguous to the Service Area in which the Generating Unit is located, in proportion to the benefits that each such Participating TO receives, as determined by the ISO. Where the costs allocated under this section are allocated to two or more Participating TOs, the ISO shall file the allocation under Section 205 of the Federal Power Act. For the purposes of this section, the incremental locational cost shall be the additional costs associated with committing and operating a particular unit or units to meet a local reliability requirement over the costs of a less expensive unit or units that would have been committed and operated absent the local reliability requirement. If a unit is committed in real-time for local reliability, its Minimum Load costs shall be considered incremental locational costs. Costs allocated under this part (1) shall be considered Reliability Services Costs.

(2) if the Generating Unit was operating due to Zonal requirements, the Minimum Load Costs shall be allocated on a monthly basis to each Scheduling Coordinator in the constrained Zone based on the ratio of that Scheduling Coordinator's monthly Demand to the sum of all Scheduling Coordinator's monthly Demand in that Zone;

(3) if the Generating Unit was operating to satisfy an ISO Control Area-wide need, the ISO shall allocate the Minimum Load Costs in the following way:

a. first, to the monthly absolute total of all Net Negative Uninstructed Deviation (determined for each Settlement Interval based on Final Hour-Ahead Schedules) at a per-MWh rate that shall not exceed a figure that is determined by dividing the total Minimum Load Cost in that month by the sum of the minimum loads for Generating Units operating under Waiver Denial Periods in that month;

b. finally, all remaining costs not allocated per (a) shall be allocated to each Scheduling Coordinator in proportion to the sum of that Scheduling Coordinator's monthly Control Area Gross Load and Demand within California outside the ISO Control Area that is served by exports to the monthly sum of the ISO Control Area Gross Load and the projected Demand within California outside the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators.

40.8.7 Payment Of Available Generation Under The FERC Must-Offer Obligation.

Available Generation that is required to be offered to the Real-Time Market, if dispatched by the ISO, shall be settled as follows: the actual amount of the dispatched Energy shall be settled at the applicable Instructed Imbalance Energy Market Clearing Price. Minimum Load Cost compensation shall be paid for all otherwise eligible hours within the Waiver Denial Period, as defined in Section 40.8.1, that the unit generated Energy above minimum operating level in compliance with ISO Dispatch Instructions.

40.9 Criteria for Issuing Must-Offer Waivers.

The ISO shall grant waivers so as to: (1) provide sufficient on-line generating capacity to meet operating reserve requirements; and (2) account for other physical operating constraints, including Generating Unit or System Unit minimum up and down times. Subject to the exceptions for Short Start Resource Adequacy Resources as identified in this ISO Tariff, the ISO shall grant, deny or revoke waivers using a security-constrained unit commitment software application to minimize start-up and Minimum Load Costs.

40.10 Requirement of FERC Must-Offer Generators to File Heat Rate and Emissions Rate Data.

Resource Adequacy Resources and FERC Must-Offer Generators, as defined in this ISO Tariff, that own or control gas-fired Generating Units or System Units must file with the ISO and the FERC, on a confidential basis, the heat rates and emissions rates for each gas-fired Generating Unit or System Unit that they own or control. Heat rate and emissions rate data shall be provided in the format specified by the ISO as posted on the ISO Website. Heat rate data provided to comply with this requirement shall not include start-up or minimum load fuel costs. Resource Adequacy Resources and FERC Must-Offer Generators must also file periodic updates of this data upon the direction of either FERC or the ISO. The ISO will treat the information provided to the ISO in accordance with this section as confidential and will apply the procedures in Section 20.4 of this ISO Tariff with regard to requests for disclosure of such information.

40.10.1 Calculation of the Proxy Price.

The ISO shall calculate each day separate Proxy Prices for each gas-fired Generating Unit or System Unit owned or controlled by a Resource Adequacy Resource or FERC Must-Offer Generator by applying the filed heat rates for those Generating Units or System Units to a daily proxy figure for natural gas costs with an additional $6.00/MWh allowed for operations and maintenance expenses. The proxy figures for natural gas costs shall be based on the most recent data available and shall be posted on the ISO Website by 8:00 AM on the day prior to which the figures will be used for calculation of the Proxy Price.

40.11 Emissions Costs.

40.11.1 Obligation to Pay Emissions Cost Charges.

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Emissions Costs incurred by a Resource Adequacy Resource or FERC Must-Offer Generator as a direct result of an ISO Dispatch Instruction, in accordance with this Section 40. The ISO shall levy this administrative charge (the “Emissions Cost Charge”) each month, against all Scheduling Coordinators based upon each Scheduling Coordinator’s Control Area Gross Load and Demand within California

outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Emissions Cost Charges in accordance with the ISO Payments Calendar.

40.11.2 Emissions Cost Trust Account.

All Emissions Cost Charges received by the ISO shall be deposited in the Emissions Cost Trust Account. The Emissions Cost Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time.

40.11.3 Rate For the Emissions Cost Charge.

The rate at which the ISO will assess the Emissions Cost Charge shall be at the projected annual total of all Emissions Costs incurred by Resource Adequacy Resources and FERC Must-Offer Generators as a direct result of ISO Dispatch Instruction, adjusted for interest projected to be earned on the monies in the Emissions Cost Trust Account, divided by the sum of the Control Area Gross Load and the projected Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators for the applicable year ("Emissions Cost Demand"). The initial rate for the Emissions Cost Charge, and all subsequent rates for the Emissions Cost Charge, shall be posted on the ISO Website.

40.11.4 Adjustment of the Rate For the Emissions Cost Charge.

The ISO may adjust the rate at which the ISO will assess the Emissions Cost Charge on a monthly basis, as necessary, to reflect the net effect of the following:

(a) the difference, if any, between actual Emissions Cost Demand and projected Emissions Cost Demand;

(b) the difference, if any, between the projections of the Emissions Costs incurred by Resource Adequacy Resources or FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions and the actual Emissions Costs incurred by Resource Adequacy Resources or FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions as invoiced to the ISO and verified in accordance with this Section 40.11; and

(c) the difference, if any, between actual and projected interest earned on funds in the Emissions Cost Trust Account.

The adjusted rate at which the ISO will assess the Emissions Cost Charge shall take effect on a prospective basis on the first day of the next calendar month. The ISO shall publish all data and

calculations used by the ISO as a basis for such an adjustment on the ISO Website at least five (5) days in advance of the date on which the new rate shall go into effect.

40.11.5 Credits and Debits of Emissions Cost Charges Collected from Scheduling Coordinators.

In addition to the surcharges or credits permitted under Section 11.6.3.3 of this ISO Tariff, the ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Emissions Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

40.11.6 Submission of Emissions Cost Invoices.

Scheduling Coordinators for Resource Adequacy Resources or FERC Must-Offer Generators that incur Emissions Costs as a direct result of an ISO Dispatch Instruction may submit to the ISO an invoice in the form specified on the ISO Website (the "Emissions Cost Invoice") for the recovery of such Emissions Costs. Emissions Cost Invoices shall not include any Emissions Costs specified in an RMR Contract for a unit owned or controlled by a FERC Must-Offer Generator. All Emissions Cost Invoices must include a copy of all final invoice statements from air quality districts demonstrating the Emissions Costs incurred by the applicable Generating Unit or System Unit, and such other information as the ISO may reasonably require to verify the Emissions Costs incurred as a direct result of an ISO Dispatch Instruction.

40.11.7 Payment of Emissions Cost Invoices.

The ISO shall pay Scheduling Coordinators for all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction. If the Emissions Costs indicated in the applicable air quality districts' final invoice statements include emissions produced by operation not resulting from ISO Dispatch Instructions, the ISO shall pay an amount equal to Emissions Costs multiplied by the ratio of the MWh associated with ISO Dispatch Instruction to the total MWh associated with such Emissions Costs. The ISO shall pay Emissions Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Emissions Cost Trust Account. To the extent there are insufficient funds available in Emissions Cost Trust Account in any

month to pay all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction, the ISO shall make pro rata payment of such Emissions Costs and shall adjust the rate at which the ISO will assess the Emissions Cost Charge in accordance with Section 40.11.4. Any outstanding Emissions Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Emissions Costs is limited to the obligation to pay Emissions Cost Charges received. All disputes concerning payment of Emissions Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

40.12 Start-Up Costs.

40.12.1 Obligation to Pay Start-Up Cost Charges.

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Start-Up Costs incurred by a Resource Adequacy Resource or FERC Must-Offer Generator as a direct result of an ISO Dispatch Instruction, in accordance with this Section 40.12. Such Start-Up Costs shall include (1) fuel and (2) auxiliary power. The ISO shall levy this charge (the "Start-Up Cost Charge"), each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Start-Up Cost Charges in accordance with the ISO Payments Calendar.

40.12.2 Start-Up Cost Trust Account.

All Start-Up Cost Charges received by the ISO shall be deposited in the Start-Up Cost Trust Account. The Start-Up Cost Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time.

40.12.3 Rate For the Start-Up Cost Charge.

The rate at which the ISO will assess the Start-Up Cost Charge shall be at the projected annual total of all Start-Up Costs incurred by Resource Adequacy Resource or FERC Must-Offer Generators as a direct result of ISO Dispatch Instruction, adjusted for interest projected to be earned on the monies in the Start-Up Cost Trust Account, divided by the sum

of the Control Area Gross Load and the projected Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area ("Start-Up Cost Demand"). The initial rate for the Start-Up Cost Charge, and all subsequent rates for the Start-Up Cost Charge, shall be posted on the ISO Website.

40.12.4 Adjustment of the Rate For the Start-Up Cost Charge.

The ISO may adjust the rate at which the ISO will assess the Start-Up Cost Charge on a monthly basis, as necessary, to reflect the net effect of the following:

(a) the difference, if any, between actual Start-Up Cost Demand and projected Start-Up Cost Demand;

(b) the difference, if any, between the projections of the Start-Up Costs incurred by FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions and the actual Start-Up Costs incurred by Resource Adequacy Resource or FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions as invoiced to the ISO and verified in accordance with this Section 40.12; and

(c) the difference, if any, between actual and projected interest earned on funds in the Start-Up Cost Trust Account.

The adjusted rate at which the ISO will assess the Start-Up Cost Charge shall take effect on a prospective basis on the first day of the next calendar month. The ISO shall publish all data and calculations used by the ISO as a basis for such an adjustment on the ISO Website at least five (5) days in advance of the date on which the new rate shall go into effect.

40.12.5 Credits and Debits of Start-Up Cost Charges Collected from Scheduling Coordinators.

In addition to the surcharges or credits permitted under Section 11.6.3.3 of this ISO Tariff, the ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Start-Up Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

40.12.6 Submission of Start-Up Cost Invoices.

Scheduling Coordinators for Resource Adequacy Resources or FERC Must-Offer Generators that incur Start-Up Costs as a direct result of an ISO Dispatch Instruction or if the ISO revokes a waiver from compliance with the FERC must-offer obligation while the unit is off-line in accordance with Section 40.6A.6 or 40.7.6 of this ISO Tariff, and Scheduling Coordinators for Generating Units or System Units operating under Condition 2 of the relevant RMR Contract which are called out-of-market in accordance with Section 11.2.4.2 of this ISO Tariff may submit to the ISO an invoice in the form specified on the ISO Website (the "Start-Up Cost Invoice") for the recovery of such Start-Up Costs. Such Start-Up Costs shall not exceed the costs which would be incurred within the start-up time for a unit specified in Schedule 1 of the Participating Generator Agreement. Start-Up Cost Invoices shall use the applicable proxy figure for natural gas costs 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 Resource Adequacy Resource or FERC Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas. Start-Up Cost Invoices shall specify the amount of auxiliary power used during the start-up and the actual price paid for that power. Start-Up Cost Invoices shall not include any Start-Up Costs specified in an RMR Contract for a unit owned or controlled by a FERC Must-Offer Generator.

40.12.7 Payment of Start-Up Cost Invoices.

The ISO shall pay Scheduling Coordinators for all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction. The ISO shall pay such Start-Up Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Start-Up Cost Trust Account. To the extent there are insufficient funds available in the Start-Up Cost Trust Account in any month to pay all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction, the ISO shall make pro rata payment of such Start-Up Costs and shall adjust the rate at which the ISO will assess the Start-Up Cost Charge in accordance with Section 40.12.4. Any outstanding Start-Up Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay

Start-Up Costs is limited to the obligation to pay Start-Up Cost Charges received. All disputes concerning

payment of Start-Up Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

40.13 ISO Default Qualifying Capacity Criteria.

40.13.1 Applicability.

The criteria in Section 40.13 shall apply only where a Local Regulatory Authority does not establish criteria to determine the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity for such eligible resource types.

40.13.2 Nuclear and Thermal.

Nuclear and thermal units, other than Qualifying Facilities ("QFs") with effective contracts under the Public Utility Regulatory Policies Act addressed in Section 40.13.8 below, must be a Participating Generator or a System Unit. The Qualifying Capacity of nuclear and thermal units, other than Qualifying Facilities addressed in Section 40.13.8, will be based on net dependable capacity defined by North American Electric Reliability Council ("NERC") Generating Availability Data System ("GADS") information.

40.13.3 Hydro.

Hydro units, other than QFs with contracts under the Public Utility Regulatory Policies Act, must be either Participating Generators or System Units. The Qualifying Capacity of a pond or pumped storage hydro unit, other than a QF, will be determined based on net dependable capacity defined by NERC GADS minus variable head de-rate based on an average dry year reservoir level. The Qualifying Capacity of a pond or pumped storage hydro unit that is a QF will be determined based on historic performance during the Standard Offer 1 peak hours of noon to 6:00 p.m., using a three-year rolling average.

The Qualifying Capacity of all run-of-river hydro units, including QFs, will be based on net dependable capacity defined by NERC GADS minus an average dry year conveyance flow, stream flow, or canal head de-rate. As used in this section, average dry year reflects a one-in-five year dry hydro scenario (for example, using the 4th driest year from the last 20 years on record).

40.13.4 Unit-Specific Contracts.

Unit-specific contracts with Participating Generators or System Units will qualify as Resource Adequacy capacity subject to the verification that the total MW quantity of all contracts from a specific unit do not exceed the total Net Qualifying Capacity (MW) consistent with the Net Qualifying Capacity determination for that unit.

40.13.5 Contracts with Liquidated Damage Provisions.

Firm energy contracts with liquidated damages provisions, as generally reflected in Service Schedule C of the Western Systems Power Pool Agreement or the Firm LD product of the Edison Electric Institute pro forma agreement, or any other similar firm energy contract that does not require the seller to source the energy from a particular unit, and specifies a delivery point internal to the ISO Control Area entered into before October 27, 2005 shall be eligible to count as Qualifying Capacity until the end of 2008. A Scheduling Coordinator, however, cannot have more than 75% of its portfolio of Qualifying Capacity met by contracts with liquidated damage provisions for 2006. This percentage will be reduced to 50% for 2007 and 25% for 2008.

40.13.6 Wind and Solar.

As used in this Section, wind units are those wind Generating Units without backup sources of generation and solar units are those solar Generating Units without backup sources of generation. Wind and Solar units, other than QFs with effective contracts under the Public Utility Regulatory Policies Act, must be participants in the ISO's Participating Intermittent Resource Program ("PIRP").

The Qualifying Capacity of all wind or solar units, including QFs, will be based on their monthly historic performance during the Standard Offer 1 peak hours of noon to 6:00 p.m., using a three-year rolling average. New wind and solar generators which do not have three years of historic performance data will be assigned a default Qualifying Capacity for each year of the missing historical performance as follows: the Qualifying Capacity of another solar or wind generator with historic data located in the same weather regime with similar technology adjusted for the nameplate capacity ratio of the new generator and the similarly situated proxy generator. The supporting data and the sample Qualifying Capacity calculation will be submitted to the ISO for approval as part of the facilities PIRP program application.

The default Qualifying Capacity values will be replaced on a year by year basis with actual performance data as the data becomes available to form a three year rolling average.

40.13.7 Geothermal.

Geothermal units, other than QFs addressed in Section 40.13.8, must be Participating Generators or System Units. The Qualifying Capacity of geothermal units, other than QFs addressed in Section 40.13.8, will be based on NERC GAD net dependable capacity minus a de-rate for steam field degradation.

40.13.8 Treatment of Qualifying Capacity for QFs.

QFs must be Participating Generators (signed a Participating Generator or QF Participating Generator Agreement) or System Units, unless they have a PURPA contract. Except for hydro, wind, and solar QFs addressed pursuant to Sections 40.13.3 and 40.13.6 above, the Qualifying Capacity of QFs under PURPA contracts, will be based on historic monthly generation output during Standard Offer 1 peak hours of noon to 6:00 p.m. (net behind the meter loads) during a three-year rolling average.

40.13.9 Participating Load Resources.

The Qualifying Capacity of Participating Load shall be the average reduction in demand for over a three-year period on a per dispatch basis or, if the Participating Load does not have three years of performance history, based on comparable evaluation data using similar programs. Participating Load resources must be available at least 48 hours and if the Participating Load can only be dispatched for a maximum of two hours per event, than only 0.89% of a Scheduling Coordinator's portfolio may be made up of such Participating Load.

40.13.10 Jointly-Owned Facilities.

A jointly-owned facility must be either a Participating Generator or a System Unit. The Qualifying Capacity for the entire facility will be determined based on the type of resource as described elsewhere in this Section. In addition, the Scheduling Coordinator must provide the ISO with a demonstration of its entitlement to the output of the jointly-owned facility's Qualified Capacity and an explanation of how that entitlement may change if the facility's output is restricted.

40.13.11 Facilities Under Construction.

The Qualifying Capacity for facilities under construction will be determined based on the type of resource as described elsewhere in this Section. In addition, the facility must have been in commercial operation for no less than one month to be eligible to be included as a Resource Adequacy Resource in a Scheduling Coordinator's monthly plan.

40.13.12 System Resources.

40.13.12.1 Dynamically Scheduled System Resources.

Dynamically Scheduled System Resources shall be treated similar to resources within the ISO Control Area, except with respect to the deliverability screen under Section 40.5.2.1. However, eligibility as a Resource Adequacy Resource is contingent upon a showing by the Scheduling Coordinator that the Dynamically Scheduled System Resource has secured transmission through any intervening Control Areas for the operating hours that cannot be curtailed for economic reasons or bumped by higher priority transmission and that the Load Serving Entity upon which the Scheduling Coordinator is scheduling Demand has an allocation of import capacity at the import Scheduling Point under Section 40.5.2.2 of the ISO Tariff that is not less than the Resource Adequacy Capacity provided by the Dynamically Scheduled System Resource.

40.13.12.2 Non-Dynamically Scheduled System Resources.

For Non-Dynamically Scheduled System Resources, the Scheduling Coordinator must demonstrate that the Load Serving Entity upon which the Scheduling Coordinator is scheduling Demand has an allocation of import allocation at the import Scheduling Point under Section 40.5.2.2 of the ISO Tariff that is not less than the Resource Adequacy Capacity from the Non-Dynamically Scheduled System Resource. Eligibility as Resource Adequacy Capacity would be contingent upon a showing by the Scheduling Coordinator of the System Resource that it has secured transmission through any intervening Control Areas for the operating hours that cannot be curtailed for economic reasons or bumped by higher priority transmission.

With respect to Non-Dynamically Scheduled System Resources, any inter-temporal constraints such as multi-hour run blocks, must be explicitly identified in the monthly Resource Adequacy Plan, and no

constraints may be imposed beyond those explicitly stated in the plan.

41 Procurement of RMR.

42 Assurance of Adequate Generation and Transmission to meet Applicable Operating and Planning Reserve.

42.1 Generation Planning Reserve Criteria.

Generation planning reserve criteria shall be met as follows:

42.1.1 On an annual basis, the ISO shall prepare a forecast of weekly Generation capacity and weekly peak Demand on the ISO Controlled Grid. This forecast shall cover a period of twelve months and be posted on the WEnet and the ISO may make the forecast available in other forms at the ISO's option.

42.1.2 If the forecast shows that the applicable WECC/NERC Reliability Criteria can be met during peak Demand periods, then the ISO shall take no further action.

42.1.3 If the forecast shows that the applicable WECC/NERC Reliability Criteria cannot be met during peak Demand periods, then the ISO shall facilitate the development of market mechanisms to bring the ISO Controlled Grid during peak periods into compliance with the Applicable Reliability Criteria (or such more stringent criteria as the ISO may impose pursuant to Section 7.2.2.2). The ISO shall solicit bids for Replacement Reserve in the form of Ancillary Services, short-term Generation supply contracts of up to one (1) year with Generators, and Load curtailment contracts giving the ISO the right to reduce the Demands of those parties that win the contracts when there is insufficient Generation capacity to satisfy those Demands in addition to all other Demands. The curtailment contracts shall provide that the ISO's curtailment rights can only be exercised after all available Generation capacity has been fully utilized unless the exercise of such rights would allow the ISO to satisfy the Applicable Reliability Criteria at lower cost, and the curtailment rights shall not be exercised to stabilize or otherwise influence prices for power in the Energy markets.

42.1.4 If Replacement Reserve, short-term Generation supply contracts or curtailment contracts are required to meet Applicable Reliability Criteria, the ISO shall select the bids that permit the satisfaction of those Applicable Reliability Criteria at the lowest cost.

42.1.5 Notwithstanding the foregoing, if the ISO concludes that it may be unable to comply with the Applicable Reliability Criteria, the ISO shall, acting in accordance with Good Utility Practice, take such steps as it considers to be necessary to ensure compliance, including the negotiation of contracts through processes other than competitive solicitations. The steps can include the negotiation of contracts for Ancillary Services on a real time basis. If the ISO is unable to obtain such Ancillary Services from within the ISO Controlled Grid, the ISO may solicit Ancillary Services from other Control Areas on a real-time basis.

42.1.6 The ISO may, in addition to the required annual forecast, publish a forecast of the peak Demands and Generation resources for two or more additional years. This forecast would be for information purposes to allow Market Participants to take appropriate steps to satisfy the Applicable Reliability Criteria, and would not be used by the ISO to determine whether additional resources are necessary.

42.1.7 In fulfilling its requirement to ensure that the applicable Generation planning reserve criteria are satisfied, the ISO shall rely to the maximum extent possible on market forces.

42.1.8 Except where and to the extent that such costs are recovered from Scheduling Coordinators pursuant to Section 8, and except as provided in Section 42.1.9, all costs incurred by the ISO in any hour pursuant to any contract entered into under this Section 42.1 shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordinator's metered hourly Demand (including exports) bears to the total metered hourly Demand (including exports) served in that hour.

42.1.9 Costs incurred by the ISO pursuant to any contract entered into under this Section 42.1 for resources to meet any portion of the anticipated difference between forward schedules and the real-time deviations from those schedules shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordinator’s obligation for deviation Replacement

Reserve in the hour, determined in accordance with Section 8.12.3A bears to the total deviation

Replacement Reserve in that hour.

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.
Aggregate Credit Limit	The sum of a Market Participant's or FTR Bidder's Unsecured Credit Limit and its Financial Security Amount, as provided for in Section 12 of the ISO Tariff.
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 Services.
Annual Peak Demand Forecast	A Demand Forecast of the highest Hourly Demand in any hour in a calendar year, in MW.
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 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.
"Area Control Error (ACE)"	The sum of the instantaneous difference between the actual net interchange and the scheduled net interchange between the ISO Control Area and all adjacent Control Areas and the ISO Control Area's frequency correction and time error correction obligations.
Authorized Users	A person or an entity identified as an authorized user in a meter service agreement between the ISO and an ISO Metered Entity or a meter service agreement between the ISO and a SC.
Automatic Mitigation Procedure (AMP)	The market power mitigation procedure described in Attachment A to Appendix P.
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.
Backup ISO Control Center	The ISO Control Center located in Alhambra, California.
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.
Certificate of Compliance	A certificate issued by the ISO which states that the Metering Facilities referred to in the certificate satisfy the certification criteria for Metering Facilities contained in the ISO Tariff.
Check Meter	A redundant revenue quality meter which is identical to and of equal accuracy to the primary revenue quality meter connected at the same metering point which must be certified in accordance with the ISO Tariff.
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.
Compatible Meter Data Server	A meter data acquisition and processing system which is capable of passing Meter Data and/or Settlement Quality Meter Data to MDAS via File Transfer Protocol (FTP) and which has been certified by the ISO or its authorized representative.
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.
Congestion Zone	A Zone identified as an Active Zone in Appendix I of the ISO 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) Station Power that is netted pursuant to Section 10.1.3 (b) Load that is isolated electrically from the ISO Control Area (*i.e.*, Load that is not synchronized with the ISO Control Area).

Control Area Operator	The person responsible for managing the real-time operations of a Control Area.
Converted Rights	Those transmission service rights as defined in Section 16.21A.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 0	The Trading Day to which the Settlement Statement or Settlement

	calculation refers. For example "Day 41" shall mean the 41st day after that Trading Day and similar expressions shall be construed accordingly.
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

	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 40.11.
Emissions Cost Demand	The level of Demand specified in Section 40.11.3.
Emissions Cost Invoice	The invoice submitted to the ISO in accordance with Section 40.11.6.
Emissions Cost Trust Account	The trust account established in accordance with Section 40.11.2.
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	A consumer of electric power who consumes such power to satisfy a

End-User	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.
Estimated Aggregate Liability	The sum of a Market Participant's or FTR Bidder's known and reasonably estimated potential liabilities for a specified time period arising from charges described in the ISO Tariff, as provided for in Section 12 of the ISO Tariff.
Ex Post GMM	GMM that is calculated utilizing the real-time Power Flow Model in accordance with Section 27.2.1.2.1.2.
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 16.2.1.1 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.
Fed-Wire	The Federal Reserve Transfer System for electronic funds transfer.
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.
FERC Must-Offer Generator	All entities defined by Section 40.7.1 of this ISO Tariff.
Final Approval	A statement of consent by the ISO Control Center to initiate a scheduled Outage.
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.

Financial Security	Any of the types of financial instruments listed in Section 12 of the ISO Tariff that are posted by a Market Participant or FTR Bidder.
Financial Security Amount	The level of Financial Security posted in accordance with Section 12 of the ISO Tariff by a Market Participant or FTR Bidder.
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	The operating region of a resource wherein the resource cannot

Region	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.
Forecast Fee	The charge imposed on a Participating Intermittent Resource pursuant to the terms of Appendix Q and ISO Tariff Appendix F, Schedule 4.
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 36.4 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 36.4 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 net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.
GCC	The single point of contact at the grid control center of Southern California Edison Company.
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 11.2.2.2 through the eight service charges described in Section 11.2.2.3 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 1) Load with respect to which the

	Wheeling Access Charge is payable, 2) Load that is exempt from the Access Charge pursuant to SPP 4.1, 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 26.1 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 26.1.
Host Control Area	The Control Area in which a System Resource subject to this ISO Tariff is connected to the electric grid. The Host Control Area may, or may not, be directly interconnected with the ISO Control Area.

Hour-Ahead Relating to an Hour-Ahead Market or an Hour-Ahead Schedule.

ISO Application File Template	All information (administrative, financial and technical) pertaining to Scheduling Coordinators which must be maintained in a current form by the ISO and the Scheduling Coordinator.
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 this Appendix A) in accordance with the procedures established by the ISO pursuant to the Sections of this ISO Tariff 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 7.1.1 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, 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 Station Power that is netted pursuant to Section 10.1.3) 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 Metered Entity Meter Service Agreements	The meter service agreements between the ISO and ISO Metered Entities**.**
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 9.3 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 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 Surplus Account	The account established by the ISO pursuant to Section 11.8.5.3.
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.

ISO Website	The ISO internet home page at http://www.caiso.com or such other internet address as the ISO shall publish from time to time.
ISP (Internet Service Provider)	An independent network service organization engaged by the ISO to establish, implement and operate WEnet.
Joint Powers Agreement	An agreement governing a Joint Powers Authority that is subject to the California Joint Exercise of Powers Act (California Government Code, Section 6500, *et seq.*).
Joint Powers Authority	An authority authorized by law through which two or more public entities jointly exercise their powers.
Large Generating Facility	A Generating Facility having a Generating Facility Capacity of more than 20 MW.
Line Loss Correction Factor	The line loss correction factor as set forth in the Technical Specifications.
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-Serving Entity (LSE)	Any entity (or the duly designated agent of such an entity, including, e.g. a Scheduling Coordinator), including a load aggregator or power marketer; (i) serving End Users within the ISO Control Area and (ii) that has been granted authority or has an obligation pursuant to California State or local law, regulation, or franchise to sell electric energy to End Users located within the ISO Control Area or (iii) is a Federal Power Marketing Authority that serves retail Load.
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 unique to the transmission systems of each of the PTOs established at the later of: (1) ISO Operations Date, or (2) the date upon which a New Participating TO places its facilities under

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 Change in Financial Condition A change in or potential threat to the financial condition of a Market Participant or FTR Bidder that increases the risk that the Market Participant or FTR Bidder will be unlikely to meet some or all of its financial obligations. The types of Material Change in Financial Condition include but are not limited to the following:

(a) a credit agency downgrade;

(b) being placed on a credit watch list by a major rating agency;

(c) a bankruptcy filing;

(d) insolvency;

(e) the filing of a material lawsuit that could significantly and adversely affect past, current, or future financial results; or

(f) any change in the financial condition of the Market Participant or FTR Bidder which exceeds a five percent reduction in the Market Participant's or FTR Bidder's tangible net worth for the Market Participant or FTR Bidder's preceding fiscal year, calculated in accordance with generally accepted accounting practices.

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.

MDAS The ISO's revenue meter data acquisition and processing system.

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.
Meter Data Exchange Format	The format for submitting Meter Data to the ISO which will be published by the ISO on the ISO Home Page or available on request to the Meter and Data Acquisition Manager, ISO Client Service Department.
Meter Data Request Format	The format for requesting Settlement Quality Meter Data from the ISO which will be published by the ISO on the ISO Home Page or available on request to the Meter and Data Acquisition Manager, ISO Client Service Department.
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.
Metering Facilities	Revenue quality meters, instrument transformers, secondary circuitry, secondary devices, meter data servers, related communication facilities and other related local equipment.
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 4.9.1.
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.
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 36.4.3 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 36.4.3 FTRs; minus b) Usage Charges that are: i) incurred by the Scheduling Coordinator for the New Participating TO under ISO Tariff Section 27.1.2.1.4 ii) associated with the New Participating TO's Section 36.4.3 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 27.1.2.1.7, 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 36.4.3 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.
Net Output	The gross Energy output from a Generating Unit less the Station

	Power requirements for such Generating Unit during the Netting Period, or the Energy available to provide Remote Self-Supply from a generating facility in another Control Area during the Netting Period.
Netting Period	A calendar month, representing the interval over which the Net Output of one or more generating resources in a Station Power Portfolio is available to be attributed to the self-supply of Station Power in that Station Power Portfolio.
Net Qualifying Capacity	Qualifying capacity reduced, as applicable, based on: (1) testing and verification; and (2) deliverability restrictions. The Net Qualifying Capacity determination shall be made by the ISO pursuant to the provisions of this ISO Tariff and any applicable manual or procedure.
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 16.1 and 16.2 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.
NRC (Standards)	The reliability standards published by the NRC from time to time.
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.
On-Site Self-Supply	Energy from a Generating Unit that is deemed to have self-supplied all or a portion of its associated Station Power load

without use of the ISO Controlled Grid during the Netting Period.

Operating Reserve The combination of Spinning and Non-Spinning Reserve required to meet WECC and NERC requirements for reliable

Participating Generator	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 Part 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.
Planning Reserve Margin	A Planning Reserve Margin shall be that quantity or percentage of capacity in MWs that exceeds the Demand Forecast set forth in Section 40.3 as provided for in Section 40.4 of this ISO Tariff.
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 Part 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 Part 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.
Power System Stabilizers (PSS)	An electronic control system applied on a Generating Unit that helps to damp out dynamic oscillations on a power system. The PSS senses Generator variables, such as voltage, current and shaft speed, processes this information and sends control signals to the Generator voltage regulator.

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.
Primary ISO Control Center	The ISO Control Center located in Folsom, California.
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 24 of the ISO Tariff.
Proposal for Installation	A written proposal submitted by an ISO Metered Entity to the ISO describing a proposal for the installation of additional Metering Facilities.
Proxy Price	The value determined for each gas-fired Generating Unit owned or controlled by a Must-Offer Generator in accordance with Section 40.10.1.
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.
Qualifying Capacity	The maximum capacity of a Resource Adequacy Resource. The criteria for calculating Qualifying Capacity from Resource Adequacy Resources may be established by the CPUC or other applicable Local Regulatory Authority and provided to the ISO, or default provisions in Section 40.13 of this ISO Tariff.
Qualifying Facility	A qualifying co-generation or small power production facility recognized by FERC.
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 the ISO Tariff, to assist the ISO to maintain reliability of the ISO Controlled Grid and to carry out its functions.

	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 30.6.1.2), 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 40.8.6)
Remote Self-Supply	Positive Net Output from generating resources in the Station Power Portfolio that is deemed to have self-supplied Station Power load of other Generating Units in the Station Power Portfolio during the Netting Period, where such self-supply requires use of the ISO Controlled Grid.
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 Adequacy	The program that ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves, at or deliverable to locations and at times as may be necessary to ensure local area reliability and system reliability.
Resource Adequacy Capacity	The capacity of a Resource Adequacy Resource listed on a Resource Adequacy Plan and a Supply Plan.
Resource Adequacy Plan	A submission by a Scheduling Coordinator for a Load Serving Entity serving Load in the ISO Control Area in order to satisfy the requirements of Section 40 of this ISO Tariff.

Resource Adequacy Resource	A resource that is required to offer Resource Adequacy Capacity. The criteria for determining the types of resources that are eligible to provide Qualifying Capacity may be established by the CPUC, other applicable Local Regulatory Authority and provided to the ISO, or the default provision in Section 40.13 of this ISO Tariff.
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.
Rules of Conduct	The rules set forth in 37.2 through 37.7.
Sanction	A consequence specified in Section 37 for the violation of a Rule of Conduct, which may include a) a warning letter notifying the Market Participant of the violation and future consequences specified under Section 37 if the behavior is not corrected, or b) financial penalties. Neither referral to FERC nor rescission of payment for service not provided shall constitute a Sanction.
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.
Scheduling Coordinator 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.
Scheduling Coordinator Applicant	An applicant for certification by the ISO as a Scheduling Coordinator.
Scheduling Coordinator Application Form	The form specified by the ISO from time to time in which a Scheduling Coordinator Applicant must apply to the ISO for certification as a Scheduling Coordinator.
Scheduling Coordinator Customer	A customer of the Scheduling Coordinator Applicant or a Scheduling Coordinator for whom the Scheduling Coordinator provides services relevant to the ISO Controlled Grid.
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.

	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.
Short Start	Generating Units that that have a cycle time less than five hours (Start-Up Time plus Minimum Run Time is less than five hours) have a Start Up Time less than two hours, and that can be fully optimized with respect to this cycle time.
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	The ISO Protocol that sets forth the interconnection procedures applicable to an Interconnection Request pertaining to a Large

Procedures (LGIP)	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 40.12.
Start-Up Cost Demand	The level of Demand specified in Section 40.12.3.
Start-Up Cost Invoice	The invoice submitted to the ISO in accordance with Section 40.12.6.
Start-Up Cost Trust Account	The trust account established in accordance with Section 40.12.2.
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.

Station Power Energy for operating electric equipment, or portions thereof, located on the Generating Unit site owned by the same entity that owns the Generating Unit, which electrical equipment is used exclusively for the production of Energy and any useful thermal energy associated with the production of Energy by the Generating Unit; and for the incidental heating, lighting, air conditioning and office equipment needs of buildings, or portions thereof, that are owned by the same entity that owns the Generating Unit; located on the Generating Unit site; and used exclusively in connection with the production of Energy and any useful thermal energy associated with the production of Energy by the Generating Unit. Station Power includes the Energy associated with motoring a hydroelectric Generating Unit to keep the unit synchronized at zero real power output to provide Regulation or Spinning Reserve. Station Power does not include any Energy used to power synchronous condensers; used for pumping at a pumped storage facility; or provided during a Black Start procedure. Station Power does not include Energy to serve loads outside the ISO Control Area.

Station Power Portfolio One or more generating resources eligible to self-supply Station Power, including Generating Units in the ISO Control Area, and generating facilities outside the ISO Control Area, all of which are owned by the same entity.

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.
Supply Plan	A submission by a Scheduling Coordinator for a Resource Adequacy Resource in order to satisfy the requirements of Section 40 of this ISO Tariff.
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.
Technical Specifications	Parts B to G (inclusive) of Appendix O.
Third Party Supply	Energy that is deemed to have been purchased from third parties to supply Station Power load during the Netting Period.
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.
TOC	The single point of contact at the transmission operations center of Pacific Gas & Electric Company.
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.
Total Transfer Capability (TTC)	The amount of power that can be transferred over an interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre-contingency and post-contingency system conditions.
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.
Trading Interval	A Settlement Period as defined in the Master Definitions Supplement of the ISO Tariff.
Transformer Loss Correction Factor	The transformer loss correction factor as set forth in the Technical Specifications to be applied to revenue quality meters of ISO Metered Entities which are installed on the low voltage side of step-up transformers.
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 Ownership Rights	A non-Participating TO ownership or joint ownership right to transmission facilities within the ISO Control Area that has not executed the Transmission Control Agreement and the transmission facilities are not incorporated into the ISO Controlled Grid.
Transmission Revenue Credit	For an Original Participating TO, the proceeds received from the ISO for Wheeling service, FTR auction revenue and Usage Charges, 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. 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.
RR (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.
UDP Aggregation	Two or more units scheduled by the same Scheduling Coordinator with the same resource identification that are to be considered interchangeable for calculating the UDP.
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 27.2.1.2), 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	A deviation from the resources' Dispatch Operating Point.
Uninstructed Deviation Penalty	The penalty as set forth in Section 11.2.4.1.2 of this ISO Tariff.
Uninstructed Imbalance	The real-time change in Generation or Demand other than that

Energy	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).
Un-Recovered Minimum Load Cost	The Un-Recovered Minimum Load Cost for each hour of Waiver Denial Period shall be calculated as the difference between: (1) a resource's Minimum Load Costs as calculated in this Section for the same Settlement Interval and (2) the Imbalance Energy payment for a resource's minimum load energy in the Settlement Interval.
Unsecured Credit Limit	The level of credit established for a Market Participant or FTR Bidder that is not secured by any form of Financial Security, as provided for in Section 12 of the ISO Tariff.
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.
Validation, Estimation and Editing (VEE)	Applies to Meter Data directly acquired by the ISO. Validation is the process of checking the data to ensure that it is contiguous, within pre-defined limits and has not been flagged by the meter. Estimation and Editing is the process of replacing or making complete Meter Data by using data from redundant meters, schedules, PMS or, if necessary, statistical estimation.
Value Added Network (VAN)	A data communications service provider that provides, stores and forwards electronic data delivery services within its network and to subscribers on other VANs. The data is mostly EDI type messages.
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 40.7.6.

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.
Weekly Peak Demand Forecast	Demand Forecast of the highest Hourly Demand in any hour in a period beginning at the start of the hour ending 0100 on Sunday and ending at the end of the hour ending 2400 the following Saturday, in MW.

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 Interconnection	A network of transmission lines embodied within the WECC region.
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 26.1. 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 16.1 and 16.2, 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 16.1 and 16.2, 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	The Western Systems Coordinating Council Reliability Criteria

Unless the Participating Generator fails to test at the values in the proposed change(s), the change will become effective upon the effective date for the next scheduled update of the Master File, provided the Participating Generator submits the changed information by the applicable deadline. Subject to such notification this Agreement shall not apply to any Net Scheduled QF identified in Schedule 1 which the Participating Generator no longer owns nor has contractual entitlement.

4.2 Agreement Subject to ISO Tariff. The Parties will comply with all applicable provisions of the ISO Tariff, including Sections 7.4, 8.2.3.4 and 4.6 except as expressly provided in Sections 4.2.1 through 4.2.5 of this Agreement.

4.2.1 Net Generation Metering. Notwithstanding Sections 10.1.3 of the ISO Tariff, the Participating Generator may net the value for the Generation produced by each Net Scheduled QF listed in Schedule 1 and the value for the Demand of the Self-provided Load that is (i) served by the Net Scheduled QF and (ii) electrically located on the same side of the Point of Demarcation.

4.2.2 Meter and Telemetry Location. The Participating Generator may satisfy the provisions of the ISO Tariff for the installation of meters and telemetry by installing at the Point of Demarcation meters and telemetry for the purpose of recording the net impact of the Net Scheduled QF upon the ISO-Controlled Grid; provided that the installed meters and telemetry satisfy the technical functional and performance requirements for meters and telemetry set forth in the ISO Tariff.

4.2.3 Scheduling, Billing and Settlement. For scheduling, billing, and settlement purposes regarding Net Scheduled QF Self-provided Load, measurements shall be made at the Point of Demarcation.

4.2.4 Operating Limitations. Net Scheduled QF operating limitations shall be set forth in Schedule 1 of this Agreement , the resource data template used for transmittal of Participating Generator technical data to the ISO pursuant to the ISO Tariff, or as otherwise mutually agreed to by the Parties.

4.2.5 Limitations on ISO Operating Orders. The ISO will not knowingly issue an operating order that: (1) requires the Participating Generator to reduce its Generation below the delineated minimum operating limit, other than in a System Emergency; (2) conflicts with operating instructions provided by the Participating Generator; or (3) results in damage to the Participating Generator's equipment, provided that any such equipment limitation has been provided to the ISO and incorporated in the Participating Generator's operating instructions to the ISO. If the Participating Generator: (1) receives a Final Schedule which requires operation below the minimum operating limit, and (2) deviates from that Final Schedule to continue to operate at the minimum operating limit, it will not be subject to any penalties or sanctions as a result of operating at the minimum operating limit. The Participating Generator's consequences for deviating from Final Schedules in real-time will be governed by the ISO Tariff.

4.3 Obligations Relating to Ancillary Services

4.3.1 Submission of Bids. When the Scheduling Coordinator on behalf of the Participating Generator submits a bid for Ancillary Services, the Participating Generator will, by the operation of this Section 4.3.1, warrant to the ISO that it has the capability to provide that service in accordance with the ISO Tariff and that it will comply with ISO Dispatch instructions for the provision of the service in accordance with the ISO Tariff.

4.3.2 Certification. The Participating Generator shall not use a Scheduling Coordinator to submit a bid

4.3.3 for the provision of an Ancillary Service or submit a schedule for the self provision of an Ancillary Service unless the Scheduling Coordinator serving that Participating Generator is in possession of a current certificate pursuant to Sections 8.4 and 8.10 of the ISO Tariff.

4.4 Obligations relating to Major Incidents

4.4.1 Major Incident Reports. The Participating Generator shall promptly provide such information as the ISO may reasonably request in relation to major incidents, in accordance with Section 4.6.7.3 of the ISO Tariff.

4.5 Dispatch and Curtailment. The ISO shall only dispatch or curtail a Net Scheduled QF of the Participating Generator: (a) to the extent the Participating Generator bids Energy or Ancillary Services from the Net Scheduled QF into the ISO's markets or the Energy is otherwise available to the ISO under Section 40.7.4 of the ISO Tariff; or (b) if the ISO must dispatch or curtail the Net Scheduled QF in order to respond to an existing or imminent System Emergency or condition that would compromise ISO Control Area integrity or reliability as provided in Sections 7, 7.3.1, and 11.2.4.2.1 of the ISO Tariff.

4.6 Information to Be Provided by Participating Generator. The Participating Generator shall provide to the ISO (a) a copy of the FERC order providing Qualifying Facility status to the Net Scheduled QF listed in Schedule 1, (b) a copy of any existing power purchase agreement with a UDC for the Net Scheduled QF listed in Schedule 1, and (c) a copy or a summary of the primary terms of any agreement for standby service with a UDC or MSS Operator. The Participating Generator shall notify the ISO promptly of any change in the status of any of the foregoing.

ARTICLE V

PENALTIES AND SANCTIONS

5.1 Penalties. If the Participating Generator fails to comply with any provisions of this Agreement, the ISO shall be entitled to impose penalties and sanctions on the Participating Generator. No penalties or sanctions may be imposed under this Agreement unless a Schedule providing for such penalties or sanctions has first been filed with and made effective by FERC. Nothing in the Agreement, with the exception of the provisions relating to ADR, shall be construed as waiving the rights of the Participating Generator to oppose or protest any penalty proposed by the ISO to the FERC or the specific imposition by the ISO of any FERC-approved penalty on the Participating Generator.

5.2 Corrective Measures. If the Participating Generator fails to meet or maintain the requirements set forth in this Agreement and/or in the ISO Tariff as limited by the provisions of this Agreement, the ISO shall be permitted to take any of the measures, contained or referenced in the ISO Tariff, which the ISO deems to be necessary to correct the situation.

ISO TARIFF APPENDIX F

SCHEDULE 5

STATION POWER CHARGES

The ISO shall assess a charge of $500 to the Scheduling Coordinator representing the owner of one or more Generating Units that submits an application to establish a Station Power Portfolio or to change the configuration of Station Power meters or the generating facilities included in a Station Power Portfolio. If the generating facilities in a single Station Power Portfolio are scheduled by more than one Scheduling Coordinator, then the Scheduling Coordinator representing the most installed capacity shall be assessed the application charge.

A charge of $200 will be assessed to the SC of Generating Units that have Station Power meters each time the ISO is required to shift meter data to a unique load identifier pursuant to the Station Power Protocol. For example, if a Scheduling Coordinator has two Station Power meters, and both Remote Self Supply and Third Party Supply is attributed to each Station Power meter in a single Netting Period, then the ISO must shift meter data to a total of four unique load identifiers and the charge would be $800 in that month (2 meters X 2 load IDs X $200).

All revenue collected by the ISO pursuant to this Schedule 5 shall be considered “Other Revenues” and applied as a credit to the Grid Management Charge revenue requirement in accordance with Schedule 1 of Appendix F.

where,

$MR\_DEFICIT_{i,h,o}$ = Market Revenue deficit for resource i in hour h for Settlement interval o based on the difference between the expected revenues earned in the Settlement Interval and and/or its bid cost;$MR\_SURPLUS_{i,h,o}$= Market Revenue surplus for resource i in hour h for Settlement interval o based on the difference between the expected revenues earned in the Settlement Interval and/or its bid cost.

Resource i shall receive a share of its total cost recovery in each Settlement Interval o that is included in the $COST\_RECOVERY_{i,d}$ calculation.

$$COST\_RECOVERY_{i,h,o} = COST\_RECOVERY_{i,d} / n$$

where,

n is the number of Settlement Intervals o that are included in the $COST\_RECOVERY_{i,d}$ calculation for resource i in Trade Day d.

Calculation of Market Revenue Surplus or Deficit

The market revenue surplus or deficit for each resource i will be computed for each Settlement Interval o based on the difference between the revenues earned in the Settlement Interval at the relevant 10-minute Ex Post price and the resource's bid cost (less than or equal to the Maximum Bid Level) as follows:

$$MR\_DIFF_{i,h,o} = \left(\sum_{1}^{k} \sum_{1}^{m} IIE\_ECON_{i,h,o,k,m} + \sum_{1}^{k} \sum_{1}^{m} RIE_{i,h,o,k,m} \right) * STLMT\_PRICE_{i,h,o} - BID\_COST_{i,h,o} - BID\_COST\_RIE_{i,h,o}$$

for all incremental energy bid segments *m* with $IIE\_PRICE_{i,h,o,k,m}$ and $RIE\_PRICE_{i,h,o,k,m}$ less than or equal to the Maximum Bid Level and all decremental energy bid segments *m* with $IIE\_PRICE_{i,h,o,k,m}$ and $RIE\_PRICE_{i,h,o,k,m}$ greater than or equal to the Bid Floor.

$$MR\_DEFICIT_{i,h,o} = min(0, MR\_DIFF_{i,h,o})$$

$$MR\_SURPLUS_{i,h,o} = \max(0, MR\_DIFF_{i,h,o})$$

where,

$$BID\_COST_{i,h,o} = \left(\sum_{1}^{k} \sum_{1}^{m} IIE\_ECON_{i,h,o,k,m} * IIE\_PRICE_{i,h,o,k,m} \right)$$

$$BID\_COST\_RIE_{i,h,o} = \sum_{1}^{k} \sum_{1}^{m} RIE_{i,h,o,k,m} * RIE\_PRICE_{i,h,o,k,m}$$

D 2.6.1 Tolerance Band and Performance Check

The ISO shall determine the Tolerance Band for each Settlement Interval *o* for PGA resources and dynamically scheduled System Resources based on the data from the Master File as follows:

$$TOLERANCE\_BAND_{i,h,o} = \pm \max\left(FIX\_LIM\ , TOL\_PERCENT\ * P\max_i\right) / 6$$

where,

FIX_LIM is a fixed MW limit and is initially equal to 5 MW.

TOL_PERCENT is a fixed percentage and is initially equal to 3%.$Pmax_i$ is the maximum operating capacity in MW of resource *i* specified in the Master File.

The ISO shall determine the Tolerance Band for each Settlement Interval o *for PLA resources as follows*:

$$TOLERANCE\_BAND_{i,h,o} = \pm\ max\left(FIX\_LIM\ ,\ TOL\_PERCENT * HAfin_{i,h}\right) / 6$$

where $HAfin_{i,h}$ *is the* Final Hour Ahead Energy Schedule.

Resources must operate within their relevant Tolerance Band in order to receive any above-Ex Post Price payments. The ISO shall determine the performance status of the resource for each Settlement Interval o. A resource shall have met its performance requirement if its $UIE_{i,h,o}$ is within its relevant Tolerance Band. A resource meeting its performance requirement in Settlement Interval o will have a $PERF\_STAT_{i,h,o} = 1$. A resource that has not met its performance requirement in Settlement Interval *o* will have a $PERF\_STAT_{i,h,o} = 0$.

Must-offer resources that produce a quantity of Energy above Minimum Load due to an ISO Dispatch Instruction during a Waiver Denial Period are not subject to the Tolerance Band requirement for purposes of receiving Minimum Load Cost Compensation, as defined in Section 40.8. Accordingly, the $PERF\_STAT_{i,h,o}$ for eligible must-offer resources, as defined in Section 40.8, shall be set to 1, irrespective of deviations outside of the Tolerance Band, for the purpose of determining eligibility for Minimum Load Cost Compensation during a Waiver Denial Period. The Tolerance Band shall be used to apply UDP during a Waiver Denial Period.

Non-dynamically scheduled System Resources do not have a Tolerance Band. Non-Participating Load Agreement (PLA) load resources are not subject to the performance requirement.

D 2.6.2 Unrecovered Costs Neutrality Allocation

For each Settlement Interval *o*, the total Unrecovered Costs for Trade Day *d* shall be allocated pro-rata to each Scheduling Coordinator *g* based on its Metered Demand, calculated as follows:

for the portion of energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ and $RIE\_PRICE_{i,h,o,k,m}$ greater than the Maximum Bid Level.

D 2.7 Transmission Loss Obligation

The transmission loss obligation charge shall be determined as follows:

For Generators:

$TL_{i,h,o} = ME_{i,h,o} * (1 - GMMa_h)$

For System Resources, the transmission loss obligation shall be determined as follows:

$TL_{i,h,o}$ =

$$\sum_{1}^{k}\sum_{1}^{v} REAL\_TIME\_FLOW_{i,h,o,k,v} * (1 - GMMa_h)$$

The transmission loss charge will be calculated based on the following formulation:

$TLC_{i,h,o}$ =

$$-\sum_{1}^{k} IIE\_LOSS_{i,h,o,k} * STLMT\_PRICE_{i,h,o} + TL_{i,h,o} * STLMT\_PRICE_{i,h,o}$$

D 2.8 Uninstructed Deviation Penalty Charges

The ISO will calculate but not assess charges for UDP according to this Section 2.8 until the first day of the month two months after the software that calculates UDP is put into service.

For negative Uninstructed Deviation Penalty billable quantities where $UDP\_BQ_{h,o} < 0$ and $ZONAL\_EX\_POST\_PRICE_{j,h,o} > 0$,

$UDP\_NEG\_Amt_i\ AMT_{i\,h,o}$ =

-1 * $UDP\_BQ_{i,h,o}$ * $ZONAL\_EX\_POST\_PRICE_{j,h,o}$ * .5

For positive UDP billable quantities where $UDP\_BQ_{i,h,o} > 0$ and $ZONAL\_EX\_POST\_PRICE_{j,h,o} > 0$, then

$UDP\_POS\_AMT_{i,h,o} = UDP\_BQ_{i,o,h} * ZONAL\_EX\_POST\_PRICE_{j,h,o}$

where,

$UDP\_BQ_{i,o,h}$ is the Uninstructed Deviation Penalty (UDP) billable quantity in MWh for a resource, or aggregated resource, denoted by i for Settlement Interval *o* of hour *h.*

$UDP\_POS\_AMT_{i,o,h}$ or $UDP\_NEG\_AMT_{i,o,h}$ are the penalty amounts in Dollars for either an aggregated or individual resource *i* for Settlement Interval *o* of hour *h.*

The ISO will not calculate UDP settlement amounts for Settlement Intervals when the corresponding Zonal Settlement Interval Ex Post Price is negative or zero.

For an MSS that has elected to follow its own Load, the Scheduling Coordinator for the MSS Operator will be assessed the Uninstructed Deviation Penalty charges based on the Deviation Band and Deviation Price in Section 4.9.9.2 of the ISO Tariff.

D 2.9 Minimum Load Cost Compensation

The ISO shall calculate a Must-Offer Generator's Minimum Load Cost Compensation (MLCC), pursuant to section 40.8.1 of the ISO Tariff, as the Minimum Load Cost for each resource *i* during Settlement Interval *o* of hour *h,* as defined in section 40.8.4 of the ISO Tariff.

D 3 Meaning of terms in the formulae

D 3.1 [Not Used]

D 3.2 $COST\_AT\_STLMT\_PRICE_{i,h,o}$ - $/MWh

The sum of all dollar amounts from each dispatched bid segment for Energy quantities settled at the Resource-Specific Ex Post Price, for resource i during Settlement Interval o of hour h, and limited to those bid segments with Energy Bid prices below the Maximum Bid Level.

D 3.3 $BID\_COST_{i,h,o}$ - $/MWh

The sum of all dollar amounts from each dispatched bid portion of Energy quantities settled at the maximum of either the corresponding Energy Bid price for those bids with Energy Bid prices below the Maximum Bid Level or the Bid Floor, for resource i during Settlement Interval o during hour h.

D 3.4 $PRE\_DISP\_ABC\_BQ_{i,h,o}$ - MWh

The pre-dispatched Energy from all Energy Bids with any Energy Bid price above the Maximum Bid Level, for resource i during Settlement Interval o during hour h.

D 3.5 $IIE\_PREDISPATCH\_FOR\_SEGMENT_{i,h,o,k,m}$ - MWh

The pre-dispatched Energy for resource i during Dispatch Interval k of Settlement Interval o of hour h for bid segment m.

D 3.6 [Not Used]

D 3.6.1 [Not Used]

D 3.6.2 [Not Used]

D 3.6.3 [Not Used]

UAP 4.3 Request for Modification by a Scheduling Coordinator

A Scheduling Coordinator may request a modification to an existing aggregation up to once per calendar month. A request for modification will follow the same procedures as a new request.

ISO TARIFF APPENDIX S

Station Power Protocol

STATION POWER PROTOCOL

TABLE OF CONTENTS

STATION POWER PROTOCOL (SPP)

SPP 1 General Conditions

SPP 1.1 Procurement

Station Power may be voluntarily self-supplied through a) permitted netting as provided in Section 10.1.3 of this ISO Tariff using Energy generated contemporaneously at the same location, b) On-Site Self Supply or c) Remote Self Supply. Third Party Supply may serve Station Power only to the extent permissible under the rules and regulations of the applicable Local Regulatory Authority.

SPP 1.2 Eligibility

SPP 1.2.1 Only Station Power loads associated with Generating Units in the ISO Control Area that are part of an approved Station Power Portfolio may be self-supplied in accordance with this SPP. Each Generating Unit must be subject to a PGA, QF PGA, or MSS Agreement. Any generating facility outside the ISO Control Area owned by the same entity is eligible to provide Remote Self-Supply to Station Power loads, subject to the terms of this SPP. Generating Units wishing to self-supply Station Power shall complete the application process specified in SPP 2.

SPP 1.2.2 Station Power may be self-supplied by a single corporate entity, government agency, or joint powers agency or other legal entity organized under the laws of the State of California. A Station Power Portfolio may not include any facilities that are owned by the owner's corporate affiliates. In the case of a joint powers agency, a Station Power Portfolio may not include facilities independently owned by one or more members or other legally distinct entities. If an entity owns a portion of a jointly owned Generating Unit, such ownership share may be included in a Station Power Portfolio up to the amount of the associated entitlement to Energy from the jointly-owned Generating Unit provided that: (i) the entity has the right to call upon that Energy for its own use; and (ii) the Energy entitlement is not characterized as a sale from the jointly owned Generating Unit to any of its joint owners.

SPP 1.2.3 Net Output from generating facilities outside the ISO Control Area may be included in a Station Power Portfolio and used as a source of Remote Self-Supply to serve Station Power of Generating Units in the ISO Control Area and part of the Station Power Portfolio, so long as the following conditions are fulfilled:

(a) Imports of Net Output must be scheduled using an interchange ID specified by the ISO;

(b) Import Schedules using such interchange ID do not exceed the available Net Output of such generating facilities in any hour;

(c) Firm transmission service to a Scheduling Point that assures delivery into the ISO Control Area is secured; and

(d) Meter data for generating facilities located outside the ISO Control Area shall be subject to ISO audit to verify performance in accordance with these requirements.

SPP 1.3 Limitations

SPP 1.3.1 Station Power supplied by contemporaneous on-site Generation is treated as permitted netting under Section 10.1.3 of this ISO Tariff. This SPP neither expands opportunities for nor imposes additional conditions on permitted netting. In accordance with this ISO Tariff such contemporaneous self-supplied Station Power need not be scheduled with the ISO.

SPP 1.3.2 Self-supply of Station Power shall be strictly voluntary. Nothing in this SPP is intended to: 1) preclude a Generating Unit from purchasing Station Power pursuant to an applicable retail rate or tariff; or 2) supersede otherwise applicable jurisdiction of a Local Regulatory Authority, except in the event of a conflict between federal and state tariff provisions, in which case the federal tariff provisions will control.

SPP 2 Station Power Requirements and Review

SPP 2.1 Applications to Self-Supply Station Power

SPP 2.1.1 An application to establish a Station Power Portfolio or to modify the configuration of Station Power meters or the Generating facilities included in a Station Power portfolio must be submitted according to the process specified by the ISO and posted on the ISO Home Page, and shall include the following information:

(a) One-line diagrams clearly showing the location and ownership of all Generating Units and Station Power meters, their connection to the ISO Controlled Grid or distribution system, and the status of breakers and switchgear for normal system operation.

(b) Identification of any generating facilities outside the ISO Control Area, to be used to provide Remote Self Supply of Station Power within the proposed Station Power Portfolio. No loads associated with generating facilities outside the ISO Control Area may be supplied under this SPP.

(c) Certification that the applicant is the sole owner of all generating facilities proposed to be included in the Station Power Portfolio, and that the applicant has the right to call on Energy for its own use from its ownership share of any jointly owned facilities that are proposed to be used to self supply Station Power.

(d) Demonstration that each Station Power meter is certified in accordance with the ISO Tariff.

(e) Verification that each Station Power meter is subject to a Meter Service Agreement for ISO Metered Entities, and that each Generating Unit is bound to the ISO Tariff by a PGA, QF PGA, or MSS Agreement.

(f) Verification that the applicant has arranged for terms of service with the responsible UDC or MSS Operator for the use of any distribution facilities required to self-supply Station Power.

SPP 2.1.2 On the ISO's written request, the applicant will provide additional information that the ISO reasonably determines is necessary to verify the planned operation of the Station Power Portfolio and meet the requirements of SPP 2.1.1.

SPP 2.2 ISO Monitoring and Review

SPP 2.2.1 The ISO will take the following actions with respect to each application to establish a Station Power Portfolio:

(a) The ISO shall post on the ISO Home Page a listing of the specific Station Power meters and Generating Units located in the ISO Control Area, and any generating facilities outside the ISO Control Area, that compose each Station Power Portfolio, and which are eligible to participate in the self-supply of Station Power in accordance with this SPP.

(b) The ISO will provide the appropriate UDC or MSS Operator and the Local Regulatory Authority with one-line diagrams and other information regarding each application.

(c) The ISO will make a determination in consultation with the UDC or MSS Operator and the Local Regulatory Authority on the factual question of whether distribution facilities are involved in the requested self-supply of Station Power. Any disputes regarding such determinations shall be subject to the dispute resolution procedures of this ISO Tariff.

(d) The ISO will verify metering schemes and assign unique load identifiers consistent with the ISO Data Templates and Validation Rules that the Scheduling Coordinator responsible for each meter will be required to use for scheduling and settlement.

SPP 2.2.2 The ISO shall promptly review each application to establish or modify a Station Power Portfolio. Within ten (10) Business Days after the submittal of the application, the ISO shall notify the applicant in writing that the application is complete, or shall list any specific deficiencies or additional information that the ISO reasonably requires to complete the application. The ISO shall use all reasonable efforts to make the changes necessary for the new or modified configurations to take effect and the Station Power Portfolio to begin self-supplying Station Power within twenty (20) Business Days after a complete application is submitted. In no event shall a Station Power Portfolio begin self-supplying Station Power until any and all required changes to the configuration of metering or other equipment are completed as required under SPP 6. The ISO will have an ongoing right to request additional information reasonably necessary to verify that conditions on the self-supply of Station Power as specified in this SPP are met.

SPP 3 Self-Supply Verification and ISO Charges

SPP 3.1 Self-Supply Verification

At the end of each Netting Period, the ISO will calculate the Net Output for each Generating Unit in the Station Power Portfolio. If the Net Output is positive, then all Station Power associated with that Generating Unit, other than load netted in accordance with this ISO Tariff, will have been served by On-Site Self Supply. Any positive Net Output from facilities in the Station Power Portfolio will be available to provide Remote Self Supply to any Generating Unit with negative Net Output. If the available Remote Self Supply is less than the aggregate negative Net Output in the Station Power Portfolio, then such shortfall will be deemed to have been served by Third Party Supply. The ISO will incorporate these determinations in its accounting and billing for the Netting Period by reassigning Station Power to unique load identifiers for Remote Self Supply and Third Party Supply, as required.

SPP 3.2 Charges on Metered Demand

Station Power that is not eligible for permitted netting in accordance with Section 10.1.3 of this ISO Tariff must be scheduled in accordance with the ISO Tariff, and will be assessed all charges applicable to metered Demand under the ISO Tariff, except as provided in SPP 4.1.

SPP 3.3 Administrative Charge

Scheduling Coordinators of Generating Units that have Station Power meters shall be assessed an administrative charge in accordance with Schedule 5 of Appendix F to the ISO Tariff.

SPP 4 Transmission Service

SPP 4.1 Station Power Load that is 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 and that is determined to have been served by On-Site Self Supply shall be deemed not to have used the ISO Controlled Grid and shall not be included in the Gross Load of the applicable UDC or MSS Operator. Station Power that is served by Wheeling service and that is determined to have been served by On-Site Self Supply shall be deemed not to have used the ISO Controlled Grid and shall not be included in the hourly schedules (in kWh) of the applicable Scheduling Coordinator that are subject to the Wheeling Access Charge.

SPP 4.2 Station Power Load that is 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 and that is determined to have been served by Remote Self-Supply or Third Party Supply shall be included in the Gross Load of the applicable UDC or MSS Operator. Station Power that is served by Wheeling service and that is determined to have been served by Remote Self-Supply or Third Party Supply shall be included in the hourly schedules (in kWh) of the applicable Scheduling Coordinator that are subject to the Wheeling Access Charge.

SPP 4.3 If the Generating Unit requires the use of distribution facilities or other facilities that are not part of the ISO Controlled Grid, then the Generating Unit will be subject to the appropriate charges of the applicable UDC, MSS Operator or owner of such non-ISO Controlled Grid Facilities.

SPP 5 ENERGY PRICING

All deviations between scheduled and metered Generation or Station Power will be settled at the applicable zonal price. The determination of Net Output and attribution of On-Site Self Supply, Remote Self Supply and Third Party Supply to serving Station Power under this SPP shall apply only to determine whether Station Power was self-supplied during the Netting Period and will have no effect on the price of Energy sold or consumed by any facility in the Station Power Portfolio.

SPP 6 METERING

SPP 6.1 In order to self-supply Station Power under this SPP, a Generating Unit must be subject to a Meter Service Agreement for ISO Metered Entities pursuant to ISO Tariff Section 10.3.1. A meter certified in accordance with the ISO Tariff is required for Station Power Load taken under the SPP. Separate metering is required for any on-site Load that does not meet the definition of Station Power. Under no circumstances may ineligible Loads be included in the meter data collected by the ISO from a Station Power meter.

SPP 6.2 Any costs associated with owning or operating metering or related facilities necessary to self-supply Station Power according to the terms of this SPP are the responsibility of the owner-applicant.

SPP 6.3 A single Scheduling Coordinator must represent the unique load identifiers assigned by the ISO for On-Site Self-Supply and Remote Self-Supply associated with each Station Power meter.

SPP 7 PROVISION OF DATA TO UDC OR MSS OPERATOR

The ISO will provide the applicable UDC or MSS Operator with the amount of On-Site Self Supply, Remote Self-Supply, and Third Party Supply serving Station Power at the granularity required to allow the UDC or MSS Operator to assess charges, if any, under the applicable retail tariff(s).

ISO TARIFF APPENDIX T

Scheduling Coordinator Application

The information provided for this application will be treated as confidential information

PART A

SCHEDULING COORDINATOR APPLICATION FORM

This application is for approval as a Scheduling Coordinator ("SC") by the California Independent System Operator Corporation ("ISO") in accordance with the ISO Tariff.

I. Administrative Requirements

SC Applicant's Legal Name:

_____

Address of principal place of business:

_____

_____

_____

Authorized Representative: _____

Address: _____

_____

Phone: _____

Fax: _____

E-mail: _____

Type of entity: _____

(Municipal utility, power marketer, investor owned utility, federal or state entity or other)

State of Incorporation or Partnership: _____

Proposed commencement date for service: _____

II. Scheduling Coordinator Customer Information

2.1 The information required under Part C, the ISO Application File Template, must be provided for represented Scheduling Coordinator Metered Entities, which are Generators. The Scheduling Coordinator Applicant must submit all requested information prior to final certification, which must occur fourteen (14) days before the commencement of service.

2.2 Information for Scheduling Coordinator Metered Entities, which are End Users or Eligible Customers, must be kept in a standard business format based on generally accepted accounting principals. The ISO shall have the right to inspect and audit a Scheduling Coordinator's accounts and files relating to its Scheduling Coordinator Metered Entities after giving two Business Days notice in writing.

2.3 The Scheduling Coordinator Applicant must submit a list of all ISO Metered Entities, which it will represent.

III. Security Requirement

3.1 The Scheduling Coordinator Applicant will submit a credit application to apply for an Unsecured Credit Limit as set forth in the ISO Tariff and the ISO Credit Policy & Procedures Guide: (yes/no).

3.2 The Scheduling Coordinator Applicant will provide Financial Security in a form listed in Section 12.1.2 of the ISO Tariff: (yes/no).

Acceptable forms of Financial Security include:

(a) an irrevocable and unconditional letter of credit issued by a bank or financial institution that is reasonably acceptable to the ISO;
(b) an irrevocable and unconditional surety bond issued by an insurance company that is reasonably acceptable to the ISO;

(c) an unconditional and irrevocable guaranty issued by a company that is reasonably acceptable to the ISO;

(d) a cash deposit standing to the credit of the ISO in an interest-bearing escrow account maintained at a bank or financial institution that is reasonably acceptable to the ISO;

(e) a certificate of deposit in the name of the ISO issued by a bank or financial institution that is reasonably acceptable to the ISO;

(f) a payment bond certificate in the name of the ISO issued by a bank or financial institution that is reasonably acceptable to the ISO; or

(g) a prepayment to the ISO.

3.3 The Scheduling Coordinator Applicant must provide its bank account information before final certification. The Scheduling Coordinator Applicant's bank must be capable of performing Fed-Wire System transfers.

IV. Technical Requirements

4.1 Does the Scheduling Coordinator Applicant have the computer hardware, software and communication capabilities for interface compatibility with the ISO system for data transmission, for electronic data interchange (EDI) and for Fed-Wire System transfer accounts? (yes / no) If no, please submit a proposed completion date to be fully operational so that an ISO staff site visit can be arranged.

4.2 For Loads and Generating Units located within the ISO Controlled Grid, does the Scheduling Coordinator Applicant have any scheduling restrictions imposed by the parties they represent? (yes / no) If yes, provide full details on a separate sheet of paper.

4.3 Does the Scheduling Coordinator Applicant have adequate staffing to operate a Scheduling Coordinator's operational facility twenty-four (24) hours a day for 365 days a year? (yes / no). If no, please submit a proposed completion date to be fully operational so that an ISO staff site visit can be arranged.

V. Third Party Contractual Requirements

5.1 The Scheduling Coordinator Applicant confirms that all of its Scheduling Coordinator Customers which are located within the ISO Controlled Grid and which should execute agreements with the ISO have entered into or will enter into, prior to the certification of the Scheduling Coordinator Applicant, all required agreements with the ISO to enable them to meet the requirements of the ISO Tariff: (yes / no).

(a) Represented Generators have signed Participating Generator Agreements: (yes / no).

(b) Represented UDCs have signed UDC Operating Agreements and Meter Service Agreements: (yes / no).

(c) Represented ISO Metered Entities have signed Meter Service Agreements: (yes / no).

(d) Wholesale Customers it will represent have warranted to the Scheduling Coordinato Applicant that they are eligible for wholesale transmission service pursuant to the provisions of the FPA Section 212(h): (yes / no).

(e) Each End-Use Customer it will represent which requests Direct Access service has warranted to the Scheduling Coordinator Applicant that the End-Use Customer is eligible for such service: (yes / no).

5.2 The SCHEDULING COORDINATOR Applicant confirms that all of the parties which it represents as Scheduling Coordinator Customers have granted it all necessary agency authority, whether actual, implied or inherent, to enable the Scheduling Coordinator to perform all of its obligations under the ISO Tariff: (yes / no).

5.3 Notwithstanding 5.2, the Scheduling Coordinator confirms that it will have the primary responsibility, as the principal, for all Scheduling Coordinator payment obligations under the ISO Tariff : (yes / no).

VI. Additional Information and Obligations

6.1 The Scheduling Coordinator Applicant agrees to provide such further information to the ISO as the ISO may deem necessary to process the application and certify the Scheduling Coordinator Applicant as a Scheduling Coordinator now and on a continuing basis.

6.2 Subject to the ISO Tariff, the Scheduling Coordinator Applicant agrees to promptly report to the ISO within seven (7) Business Days or earlier any changes regarding the information provided by it referred to in the ISO Tariff and in the application with the exception of the security requirement data referred to in Part III of Part A in this Appendix which must be updated within five (5) Business Days. The Scheduling Coordinator shall be responsible if a failure to submit revised technical data more promptly extends the period during which schedules are rejected by the ISO.

6.3 The Scheduling Coordinator Applicant agrees to enclose herein the non-refundable application fee of $500 to cover the application processing costs, site visit and costs of providing ISO Tariff.

Please make check payable to:

The California Independent System Operator Corporation

6.4 Scheduling Coordinator Applicant agrees to promptly execute and return the Scheduling Coordinator Agreement, Meter Service Agreements, Interim Black Start Agreements, software licensing agreement, completed credit application, and/or Financial Security as applicable, and Fed-Wire System bank account number, after receiving its application approval letter from the ISO.

6.5 Final certification is contingent upon Scheduling Coordinator Applicant fulfilling all financial and technical requirements as referenced in the ISO Tariff (including Part C of this Appendix, the ISO Application File Template).

Scheduling Coordinator Applicant certifies by its signature on this Application Form that:

Scheduling Coordinator Application PART C

ISO APPLICATION FILE TEMPLATE

The ISO Application File Template is an Excel template used to load resources into the ISO's database. There is also a customer help file created to work with a Microsoft Access Database which are used together to gather application information.

ISO TARIFF APPENDIX U

Standard Large Generator Interconnection Procedures (LGIP)

Standard Large Generator
Interconnection Procedures (LGIP)

Table of Contents

SECTION 1. OBJECTIVES, DEFINITIONS, AND INTERPRETATION.

1.1 Objectives.

The objective of this LGIP is to implement FERC's Order No. 2003 setting forth the requirements for Large Generating Facility interconnections to the ISO Controlled Grid.

1.2 Definitions.

1.2.1 Master Definitions Supplement.

Unless the context otherwise requires, any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this LGIP. A reference to a Section or an Appendix is a reference to a Section or an Appendix of the ISO Tariff. References to LGIP are to this Protocol or to the stated paragraph of this Protocol.

1.2.2 Special Definitions for this LGIP.

In this LGIP, the following words and expressions shall have the meanings set opposite them:

"Confidential Information" shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, subject to Section 13.1 of the LGIP.

"Dispute Resolution" shall mean the procedure set forth in this LGIP for resolution of a dispute between the Parties.

"Force Majeure" shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

"Governmental Authority" shall mean any federal, state, local or other governmental, regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, ISO, or Participating TO, or any Affiliate thereof.

"Party" or "Parties" shall mean the ISO, Participating TO(s), Interconnection Customer or the applicable combination of the above.

"Reasonable Efforts" shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Procedures, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

1.2.3 Rules of Interpretation.

(a) Unless the context otherwise requires, if the provisions of this LGIP and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency.

(b) A reference in this LGIP to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this LGIP are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this LGIP.

(d) This LGIP shall be effective as of the date specified by FERC.

Section 2. Scope and Application.

2.1 Application of Standard Large Generator Interconnection Procedures.

Sections 2 through 13 of this LGIP apply to processing an Interconnection Request pertaining to a Large Generating Facility.

2.2 Comparability.

The ISO shall receive, process and analyze Interconnection Requests in a timely manner as set forth in this LGIP. The ISO will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by a Participating TO, its subsidiaries, or Affiliates or others.

2.3 Base Case Data.

The ISO and/or the applicable Participating TO(s) shall provide base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list upon request subject to applicable confidentiality provisions in LGIP Section 13.1. The applicable Participating TO(s) and the ISO are permitted to require that the Interconnection Customer sign a confidentiality agreement before the release of commercially sensitive information or Critical Energy Infrastructure Information (as that term is defined by FERC) in the Base Case data. Such Base Cases shall include (i) generation projects and (ii) transmission projects, including merchant transmission projects that are proposed for the transmission system for which a transmission expansion plan has been submitted and approved by the applicable authority.

2.4 No Applicability to Transmission Service.

Nothing in this LGIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

Section 3. Interconnection Requests.

3.1 General.

Pursuant to ISO Tariff Section 5.7.1, an Interconnection Customer shall submit to the ISO an Interconnection Request in the form of Appendix 1 to this LGIP and a refundable deposit of $10,000. The ISO will forward a copy of the Interconnection Request to the applicable Participating TO within one (1) Business Day of receipt. The ISO shall apply the deposit toward the cost of an Interconnection Feasibility Study. The Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. The Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests.

At the Interconnection Customer's option, the applicable Participating TO(s), the ISO and Interconnection Customer will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point of Interconnection to be studied and one alternative Point of Interconnection no later than the execution of the first Interconnection Feasibility Study Agreement.

3.2 Roles and Responsibilities.

(a) Each Interconnection Request will be subject to the direction and oversight of the ISO. The ISO will conduct or cause to be performed the required Interconnection Studies and any additional studies the ISO determines to be reasonably necessary, and will direct the applicable Participating TO to perform portions of studies where the Participating TO has specific and non-transferable expertise or data and can conduct the studies more efficiently and cost effectively than the ISO. The ISO will coordinate with Affected System Operators in accordance with LGIP Section 3.7.

(b) The ISO will complete or cause to be completed all studies as required within the timelines provided in this LGIP. Any portion of the studies performed at the direction of the ISO by the Participating TOs or by a third party shall also be completed within timelines provided in this LGIP.

(c) The ISO has established a pro forma Roles and Responsibilities Agreement, attached hereto and incorporated herein by reference, for execution by the ISO and the applicable Participating TOs.

(d) Each Interconnection Customer shall pay the actual costs of all Interconnection Studies, and any additional studies the ISO determines to be reasonably necessary in response to the Interconnection Request. The ISO shall reimburse the Participating TO for the actual cost of any portion of all Interconnection Studies that such Participating TO performs at the direction of the ISO.

3.3 Interconnection Service.

3.3.1 The Product. Interconnection Service allows the Interconnection Customer to connect the Large Generating Facility to the ISO Controlled Grid and be eligible to deliver the Large Generating Facility's output using the available capacity of the ISO Controlled Grid. Interconnection Service does not in and of itself convey any right to deliver electricity to any specific customer or point of delivery.

3.3.2 The Interconnection Studies. The Interconnection Studies consist of, but are not limited to, short circuit/fault duty, steady state (thermal and voltage) and stability analyses. The Interconnection Studies will identify direct Interconnection Facilities and required Reliability Network Upgrades necessary to mitigate thermal overloads and voltage violations, and address short circuit, stability, and reliability issues associated with the requested Interconnection Service.

The Interconnection Studies will also identify necessary Delivery Network Upgrades to allow full output of the proposed Large Generating Facility under a variety of potential system conditions, and the maximum allowed output, under a variety of potential system conditions, of the interconnecting Large Generating Facility without the Delivery Network Upgrades.

3.3.3 Deliverability Assessment.

3.3.3.1 The Product. A Deliverability Assessment will be performed which shall determine the Interconnection Customer's Large Generating Facility's ability to deliver its energy to the ISO Controlled Grid under peak load conditions. The Deliverability Assessment will provide the Interconnection Customer with information as to the level of deliverability without Network Upgrades, and the Deliverability Assessment will provide the Interconnection Customer with information as to the required Network Upgrades to enable the Interconnection Customer's Large Generating Facility the ability to deliver the full output of the proposed Large Generating Facility to the ISO Controlled Grid based on specified study assumptions.

Thus, the Deliverability Assessment results will provide the Interconnection Customer two (2) data points on the scale of deliverability: 1) a deliverability level with no Network Upgrades, and 2) the required Network Upgrades to support 100% deliverability.

Deliverability of a new Large Generating Facility will be assessed on the same basis as all other existing resources interconnected to the ISO Controlled Grid.

3.3.3.2 The Assessment. The Deliverability Assessment will identify the facilities that are required to enable the Interconnection Customer's Large Generating Facility to meet the requirements for deliverability and as a general matter, that such Large Generating Facility's interconnection is also studied with the ISO Controlled Grid at peak load, under a variety of severely stressed conditions, to determine whether, with the Large Generating Facility at full output, 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. This approach assumes that some portion of existing resources that are designated as deliverable is displaced by the output of the Interconnection Customer's Large Generating Facility. This Deliverability Assessment in and of itself does not convey any right to deliver electricity to any specific customer or point of delivery. The ISO Controlled Grid may also be studied under non-peak load conditions. However, upon request by the Interconnection Customer, the Deliverability Assessment must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

3.4 Network Upgrades.

3.4.1 Initial Funding

Unless the Participating TO elects to fund the capital for Reliability and Delivery Network Upgrades, they shall be solely funded by the Interconnection Customer.

3.4.2 [Section Intentionally Omitted]

3.4.3 Repayment of Amounts Advanced for Network Upgrades.

Upon the Commercial Operation Date, the Interconnection Customer shall be entitled to a repayment for the cost of Network Upgrades. Such amount shall be paid to the Interconnection Customer by the applicable Participating TO(s) on a dollar-for-dollar basis either through (1) direct payments made on a levelized basis over the five-year period commencing on the Commercial Operation Date; or (2) any alternative payment schedule that is mutually agreeable to the Interconnection Customer and Participating TO, provided that such amount is paid within five (5) years of the Commercial Operation Date. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. §35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment. The Interconnection Customer may assign such repayment rights to any person.

Instead of direct payments, the Interconnection Customer may elect to receive Firm Transmission Rights (FTRs) in accordance with the ISO Tariff associated with the Network Upgrades that were funded by the Interconnection Customer, to the extent such FTRs or alternative rights are available under the ISO Tariff at the time of the election. Such FTRs would take effect upon the Commercial Operation Date of the Large Generating Facility in accordance with the LGIA.

3.4.4 Special Provisions for Affected Systems and Other Affected Participating TOs.

The Interconnection Customer shall enter into an agreement with the owner of the Affected System and/or other affected Participating TO(s), as applicable. The agreement shall specify the terms governing payments to be made by the Interconnection Customer to the owner of the Affected System and/or other affected Participating TO(s) as well as the repayment by the owner of the Affected System and/or other affected Participating TO(s). If the affected entity is another Participating TO, the initial form of agreement will be the LGIA, as appropriately modified.

Any repayment by the owner of the Affected System shall be in accordance with FERC Order No. 2003-B (109 FERC ¶ 61,287).

3.5 Valid Interconnection Request.

3.5.1 Initiating an Interconnection Request.

To initiate an Interconnection Request, the Interconnection Customer must submit all of the following: (i) a $10,000 deposit, (ii) a completed application in the form of LGIP Part 1, and (iii) demonstration of Site Control or a posting of an additional deposit of $10,000. Such deposits may be applied toward any Interconnection Studies pursuant to the Interconnection Request. If the Interconnection Customer demonstrates Site Control within the cure period specified in LGIP Section 3.5.3 after submitting its Interconnection

Request, the additional deposit shall be refundable; otherwise, all such deposit(s), additional and initial, become non-refundable.

The expected In-Service Date of the new Large Generating Facility or increase in capacity of the existing Generating Facility shall be no more than the process window for the regional expansion planning period (or in the absence of a regional planning process, the process window for the ISO's expansion planning period) not to exceed seven years from the date the Interconnection Request is received by the ISO, unless the Interconnection Customer demonstrates that engineering, permitting and construction of the new Large Generating Facility or increase in capacity of the existing Generating Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by the ISO by a period up to ten years, or longer where the Interconnection Customer, the applicable Participating TO and the ISO agree, such agreement not to be unreasonably withheld.

3.5.2 Acknowledgment of Interconnection Request.

The ISO shall acknowledge receipt of the Interconnection Request within six (6) Business Days of receipt of the request and attach a copy of the received Interconnection Request to the acknowledgement.

3.5.3 Deficiencies in Interconnection Request.

An Interconnection Request will not be considered to be a valid request until all items in LGIP Section 3.5.1 have been received and deemed valid by the ISO. If an Interconnection Request fails to meet the requirements set forth in LGIP Section 3.5.1, the ISO shall notify the Interconnection Customer within six (6) Business Days of receipt of the initial Interconnection Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request. The Interconnection Customer shall provide the ISO the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. Failure by the Interconnection Customer to comply with this LGIP Section 3.5.3 shall be treated in accordance with LGIP Section 3.8.

3.5.4 Scoping Meeting.

Within ten (10) Business Days after the ISO notifies the Interconnection Customer of a valid Interconnection Request, the ISO shall establish a date agreeable to the Interconnection Customer and the applicable Participating TO(s) for the Scoping Meeting, and such date shall be no later than thirty (30) Calendar Days from notification of the valid Interconnection Request, unless otherwise mutually agreed upon by the Parties. The ISO shall determine whether the Interconnection Request is at or near the boundary of an affected Participating TO(s) service territory or of any other Affected System(s) so as to potentially affect such third parties. If such a determination is made, the ISO shall invite the affected Participating TO(s), and/or Affected System Operator(s) in accordance with Section 3.7, to the Scoping Meeting by informing such third parties of the time and place of the scheduled Scoping Meeting as soon as practicable.

The purpose of the Scoping Meeting shall be to discuss alternative interconnection options, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection. The applicable Participating TO(s) and the ISO will bring to the meeting such already available technical data, including, but not limited to: (i) general facility loadings, (ii) general instability issues, (iii) general short circuit issues, (iv) general voltage issues, and (v) general reliability issues, as may be reasonably required to accomplish the purpose of the meeting.

be reasonably required to accomplish the purpose of the meeting. The Interconnection Customer will bring to the Scoping Meeting as much large generator technical data in Attachment A to Appendix 1, and system studies previously performed, as available. The applicable Participating TO(s), the ISO, and the Interconnection Customer will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, the Interconnection Customer shall designate its Point of Interconnection, pursuant to LGIP Section 6.1, and one alternative Point of Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose.

The ISO shall prepare minutes from the meeting, verified by the Interconnection Customer and the other attendees, that will include, at a minimum, discussions among the applicable Participating TO(s) and the ISO of what the expected results may be for the Interconnection Feasibility Study.

3.6 Internet Posting.

The ISO will maintain on the ISO Home Page a list of all Interconnection Requests. The list will identify, for each Interconnection Request: (i) the maximum summer and winter megawatt electrical output; (ii) the location by county and state; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected In-Service Date; (v) the status of the Interconnection Request, including Queue Position; (vi) the availability of any studies related to the Interconnection Request; (vii) the date of the Interconnection Request; (viii) the type of Generating Facility to be constructed (combined cycle, base load or combustion turbine and fuel type); and (ix) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed.

Except in the case of an Affiliate, the list will not disclose the identity of the Interconnection Customer until the Interconnection Customer executes an LGIA or requests that the applicable Participating TO(s) and the ISO file an unexecuted LGIA with FERC. The ISO shall post on the ISO Home Page an advance notice whenever a Scoping Meeting will be held with an Affiliate of a Participating TO.

The ISO shall post to the ISO Home Page any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection Study reports shall be posted to the ISO Home Page subsequent to the meeting among the Interconnection Customer, the applicable Participating TO(s) and the ISO to discuss the applicable study results. The ISO shall also post any known deviations in the Large Generating Facility's In-Service Date.

3.7 Coordination with Affected Systems.

The ISO will notify the Affected System Operators that are potentially affected by the project proposed by the Interconnection Customer. The ISO will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators, to the extent possible, and, if possible, the (ISO) will include those results (if available) in its applicable Interconnection Study within the time frame specified in this LGIP. The ISO will include such Affected System Operators in all meetings held with the Interconnection Customer as required by this LGIP. The Interconnection Customer will cooperate with the ISO in all matters related to the conduct of studies and the determination of modifications to Affected Systems, including signing separate study agreements with Affected System owners and paying for necessary studies. An entity which may be an Affected System shall cooperate with the ISO in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

3.8 Withdrawal.

The Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to the ISO, and the ISO will notify the applicable Participating TO(s), within three (3) Business Days of receipt of such a notice. In addition, if the Interconnection Customer fails to adhere to all requirements of this LGIP, except as provided in LGIP Section 13.5 (Disputes), the ISO shall deem the Interconnection Request to be withdrawn and shall provide written notice to the Interconnection Customer within five (5) Business Days of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Upon receipt of such written notice, the Interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify the ISO of its intent to pursue Dispute Resolution.

Withdrawal shall result in the loss of the Interconnection Customer's Queue Position, if any. If an Interconnection Customer disputes the withdrawal and loss of its Queue Position, then during Dispute Resolution, the Interconnection Customer's Interconnection Request is eliminated from the queue until such time that the outcome of Dispute Resolution would restore its Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to the ISO all costs that have been prudently incurred or irrevocably have committed to be incurred with respect to that Interconnection Request prior to the ISO's receipt of notice described above. The Interconnection Customer must pay all monies due to the Participating TO before it is allowed to obtain any Interconnection Study data or results. The ISO will reimburse the applicable Participating TO(s) for all work performed associated with the Interconnection Request at the ISO's direction.

The ISO shall update the ISO Home Page Queue Position posting. The ISO shall refund to the Interconnection Customer any portion of the Interconnection Customer's deposit or study payments that exceed the costs that the ISO has incurred or Participating TO(s) have incurred, including interest calculated in accordance with section 35.19a(a)(2) of FERC's regulations. In the event of such withdrawal, the ISO, subject to the confidentiality provisions of LGIP Section 13.1, shall provide, at the Interconnection Customer's request, all information that the ISO developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

Section 4. Queue Position.

4.1 General.

The ISO shall assign a Queue Position based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, and the Interconnection Customer provides such information in accordance with LGIP Section 3.5.3, then the ISO shall assign the Interconnection Customer a Queue Position based on the date the application form was originally filed. Moving a Point of Interconnection shall result in a lowering of Queue Position if it is deemed a Material Modification under LGIP Section 4.4.3.

The queue position of each Interconnection Request will be used to determine the order of performing the Interconnection Studies and determination of cost responsibility for the facilities necessary to accommodate the Interconnection Request. A higher Queue Position Interconnection Request is one that has been placed "earlier" in the ISO's queue in relation to another Interconnection Request that is lower queued. The cost of the common upgrades for clustered Interconnection Requests may be allocated without regard to queue position.

4.2 Clustering.

At the ISO's option, and in coordination with the applicable Participating TO(s), Interconnection Requests may be studied serially or in clusters for the purpose of the Interconnection System Impact Study.

Clustering shall be implemented on the basis of Queue Position. If the ISO elects, in coordination with applicable Participating TO(s), to study Interconnection Requests using Clustering, all Interconnection Requests received within a period not to exceed one hundred and eighty (180) Calendar Days, hereinafter referred to as the "Queue Cluster Window" shall be studied together without regard to the nature of the underlying Interconnection Service. The deadline for completing all Interconnection System Impact Studies for which an Interconnection System Impact Study Agreement has been executed during a Queue Cluster Window shall be in accordance with LGIP Section 7.4, for all Interconnection Requests assigned to the same Queue Cluster Window. The ISO may agree to conduct the study of an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Large Generating Facility.

Clustering Interconnection System Impact Studies shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the transmission system's capabilities at the time of each study.

The Queue Cluster Window shall have a fixed time interval based on fixed annual opening and closing dates. Any changes to the established Queue Cluster Window interval and opening or closing dates shall be announced with a posting on the ISO Home Page beginning at least one hundred and eighty (180) Calendar Days in advance of the change and continuing thereafter through the end date of the first Queue Cluster Window that is to be modified.

4.3 Transferability of Queue Position.

An Interconnection Customer may transfer its Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change.

4.4 Modifications.

The Interconnection Customer shall submit to the ISO, in writing, modifications to any information provided in the Interconnection Request. The ISO will forward the Interconnection Customer's modification to the applicable Participating TO(s) within one (1) Business Day of receipt. The Interconnection Customer shall retain its Queue Position if the modifications are in accordance with LGIP Sections 4.4.1, 4.4.2 or 4.4.5, or are determined not to be Material Modifications pursuant to LGIP Section 4.4.3.

Notwithstanding the above, during the course of the Interconnection Studies, the Interconnection Customer, the applicable Participating TO(s), or the ISO may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes are acceptable to the applicable Participating TO(s), the ISO, and Interconnection Customer, such acceptance not to be unreasonably withheld, the ISO shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with LGIP Section 6.4, LGIP Section 7.6 and LGIP Section 8.5 as applicable and the Interconnection Customer shall retain its Queue Position.

4.4.1 Prior to the return of the executed Interconnection System Impact Study Agreement to the ISO, modifications permitted under this Section shall include specifically: (a) a decrease of up to 60 percent of electrical output (MW) of the proposed project; (b) modifying the technical parameters associated with the Large Generating Facility technology or the Large Generating Facility step-up transformer impedance characteristics; and (c) modifying the interconnection configuration. For plant increases, the incremental increase in plant output will go to the end of the queue for the purposes of cost allocation and study analysis.

4.4.2 Prior to the return of the executed Interconnection Facility Study Agreement to the ISO, the modifications permitted under this Section shall include specifically: (a) additional 15 percent decrease of electrical output (MW), and (b) Large Generating Facility technical parameters associated with modifications to Large Generating Facility technology and transformer impedances; provided, however, the incremental costs associated with those modifications are the responsibility of the requesting Interconnection Customer.

4.4.3 Prior to making any modification other than those specifically permitted by LGIP Sections 4.4.1, 4.4.2, and 4.4.5, the Interconnection Customer may first request that the ISO evaluate whether such modification is a Material Modification. In response to the Interconnection Customer's request, the ISO, in coordination with the affected Participating TO, shall evaluate the proposed modifications prior to making them and the ISO shall inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection, except those deemed acceptable under Sections 4.4.1, 6.1, 7.2 or so allowed elsewhere, shall constitute a Material Modification. The Interconnection Customer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

4.4.4 Upon receipt of the Interconnection Customer's request for modification permitted under this LGIP Section 4.4, the ISO shall commence and conduct or have conducted any necessary additional studies as soon as practicable, but in no event shall such studies commence later than thirty (30) Calendar Days after receiving notice of the Interconnection Customer's request. Any additional studies resulting from such modification shall be done at the Interconnection Customer's cost.

4.4.5 Extensions of less than three (3) cumulative years in the Commercial Operation Date of the Large Generating Facility to which the Interconnection Request relates are not material and should be handled through construction sequencing.

Section 5. Procedures for Interconnection Requests Submitted Prior to Effective Date of Standard Large Generator Interconnection Procedures.

5.1 Queue Position for Pending Requests.

5.1.1 Any Interconnection Customer assigned a queue position prior to the effective date of this LGIP shall retain that relative queue position.

5.1.1.1 If an Interconnection Study agreement has not been executed as of the effective date of this LGIP, then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with this LGIP.

5.1.1.2 If an Interconnection Study agreement has been executed prior to the effective date of this LGIP, such Interconnection Study shall be completed in accordance with the terms of such agreement. With respect to any remaining studies for which an Interconnection Customer has not signed an Interconnection Study agreement prior to the effective date of the LGIP, the Participating TO must offer the Interconnection Customer the option of either continuing under the Participating TO's existing interconnection study process pursuant to ISO Tariff Appendix W or going forward with the completion of the necessary Interconnection Studies (for which it does not have a signed Interconnection Studies agreement) in accordance with this LGIP.

5.1.1.3 If an agreement to interconnect a Generating Unit has been submitted to FERC for approval before the effective date of the LGIP, then the agreement would be grandfathered.

5.1.2 Transition Period.

To the extent necessary, the Participating TO and/or the ISO and Interconnection Customers with an outstanding request (i.e., an interconnection request or application for which an agreement to interconnect a Generating Unit has not been submitted to FERC for approval as of the effective date of this LGIP) shall transition to this LGIP within a reasonable period of time not to exceed sixty (60) Calendar Days. The use of the term "outstanding request" herein shall mean any interconnection request or application, on the effective date of this LGIP: (i) that has been submitted but not yet accepted by the ISO or the Participating TO; (ii) where the related interconnection agreement has not yet been submitted to FERC for approval in executed or unexecuted form, (iii) where the relevant interconnection study agreements have not yet been executed, or (iv) where any of the relevant interconnection studies are in process but not yet completed. Any Interconnection Customer with an outstanding request as of the effective date of this LGIP may request a reasonable extension of any deadline, otherwise applicable, if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension shall be granted by the ISO, as applicable, to the extent consistent with the intent and process provided for under this LGIP.

5.2 Change in ISO Operational Control.

If the ISO no longer has control of the portion of the ISO Controlled Grid at the Point of Interconnection during the period when an Interconnection Request is pending, the ISO shall transfer to applicable Participating TO which has ownership of the Point of Interconnection any amount of the deposit or payment with interest thereon that exceeds the cost that it incurred to evaluate the request for interconnection. Any difference between such net deposit amount and the costs that the successor Participating TO incurs to evaluate the request for interconnection shall be paid by or refunded to the Interconnection Customer, as appropriate. The ISO shall coordinate with the applicable Participating TO which has ownership of the Point of Interconnection to complete any Interconnection Study, as appropriate, that the ISO has begun but has not completed. If the ISO has tendered a draft LGIA to the Interconnection Customer but the Interconnection Customer has neither executed the LGIA or requested the filing of an unexecuted LGIA with FERC, unless otherwise provided, the Interconnection Customer must complete negotiations with the applicable Participating TO which has the ownership of the Point of Interconnection.

Section 6. Interconnection Feasibility Study.

6.1 Interconnection Feasibility Study Agreement.

Simultaneously with the acknowledgement of a valid Interconnection Request, the ISO shall provide to the Interconnection Customer a pro forma Interconnection Feasibility Study Agreement. The pro forma Interconnection Feasibility Study Agreement shall specify that the Interconnection Customer is responsible for the actual cost of the Interconnection Feasibility Study. Within five (5) Business Days following the Scoping Meeting, the Interconnection Customer shall specify for inclusion in the attachment to the Interconnection Feasibility Study Agreement the Point of Interconnection and one alternative Point of Interconnection. Within fifteen (15) Business Days following the ISO's receipt of such designation, the ISO, in coordination with the Participating TO shall provide to the Interconnection Customer a signed Interconnection Feasibility Study Agreement, which shall include a good faith estimate of the cost for completing the Interconnection Feasibility Study. The Interconnection Customer shall execute and deliver to the ISO the Interconnection Feasibility Study Agreement along with an additional $10,000 deposit no later than thirty (30) Calendar Days after its receipt.

On or before the return of the executed Interconnection Feasibility Study Agreement to the ISO, the Interconnection Customer shall provide to the ISO valid technical data called for in LGIP Appendix 1, Attachment A.

If the Interconnection Feasibility Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting, a substitute Point of Interconnection identified by the Interconnection Customer, the applicable Participating TO(s)and ISO, and acceptable to the others, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and re-studies shall be completed pursuant to LGIP Section 6.4 as applicable. For the purpose of this LGIP Section 6.1, if the ISO, applicable Participating TO(s) and Interconnection Customer cannot agree on the substituted Point of Interconnection, then the Interconnection Customer may direct that the alternative as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to LGIP Section 3.5.4, shall be the substitute.

If the Interconnection Customer, the applicable Participating TO, and the ISO agree to forgo the Interconnection Feasibility Study, the ISO will tender an Interconnection System Impact Study Agreement within fifteen (15) Business Days from receipt of the Interconnection Customer's designated Point of Interconnection and alternative, pursuant to the procedures specified in Section 7 of this LGIP and apply the deposits made in accordance with LGIP Section 3.5.1, in addition to the deposit made in accordance with LGIP Section 7, towards the Interconnection System Impact Study.

6.2 Scope of Interconnection Feasibility Study.

The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the ISO Controlled Grid.

The Interconnection Feasibility Study will consider Base Cases as well as all generating facilities (and with respect to (iv), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the ISO Controlled Grid; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending request to interconnect to an Affected System; (iv) have a pending higher queued Interconnection Request to interconnect to

the ISO Controlled Grid; and (v) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC. The Interconnection Feasibility Study will consist of a power flow and short circuit analysis. The Interconnection Feasibility Study will provide a list of facilities on the applicable Participating TOs' portion of the ISO Controlled Grid and a non-binding good faith estimate of cost and cost responsibility and a non-binding good faith estimated time to construct. In addition, the Interconnection Feasibility Study will describe what results are expected in the Interconnection System Impact Study and any other financial impacts (i.e., on Local Furnishing Bonds).

6.3 Interconnection Feasibility Study Procedures.

Existing studies shall be used to the extent practicable when conducting the Interconnection Feasibility Study. The ISO shall use Reasonable Efforts to complete a draft Interconnection Feasibility Study no later than forty-five (45) Calendar Days after the ISO receives the fully executed Interconnection Feasibility Study Agreement. The ISO shall share applicable study results for review and comment, provide the study results to any other potentially-impacted Participating TO(s), and incorporate comments and issue a final Interconnection Feasibility Study to the Interconnection Customer within sixty (60) Calendar Days following receipt of the fully executed Interconnection Feasibility Study Agreement. At the request of the Interconnection Customer or at any time the ISO determines that the study cannot be completed within the required time frame for completing the Interconnection Feasibility Study, the ISO shall notify the Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If the Interconnection Feasibility Study cannot be completed within that time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required.

Upon request, the ISO shall provide the Interconnection Customer supporting documentation, workpapers and relevant power flow and short circuit databases for the Interconnection Feasibility Study, subject to confidentiality arrangements consistent with LGIP Sections 2.3 and 13.1.

6.3.1 Meeting with the Participating TO(s) and ISO.

Within ten (10) Business Days of providing an Interconnection Feasibility Study report to the Interconnection Customer, the ISO, the applicable Participating TO(s), and the Interconnection Customer shall meet to discuss the results of the Interconnection Feasibility Study.

6.4 Re-Study.

If re-study of the Interconnection Feasibility Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to LGIP Section 4.4, or re-designation of the Point of Interconnection pursuant to LGIP Section 6.1, or any other effective change in information which necessitates a re-study, the ISO shall notify the Interconnection Customer and the applicable Participating TO(s) in writing along with providing a description of the expected results of the re-study. Upon receipt of such notice, the Interconnection Customer shall provide the ISO within ten (10) Business Days either a written request that the ISO (i) terminate the study and withdraw the Interconnection Request; or (ii)

continue the study. If the Interconnection Customer requests the ISO to continue the study, the Interconnection Customer shall pay the ISO an additional $10,000 deposit for the re-study along with providing written notice for the ISO to continue.

Such re-study shall take not longer than forty-five (45) Calendar Days from the date the ISO receives the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. The ISO shall share applicable study results for review, provide the study results for review and comment to any other potentially-impacted Participating TO(s), incorporate comments, and issue a final study to the Interconnection Customer within sixty (60) Calendar Days from the date the ISO receives the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. If the Interconnection Feasibility Study cannot be completed within that time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Any and all costs of the re-study shall be borne by the Interconnection Customer being re-studied.

Section 7. Interconnection System Impact Study.

7.1 Interconnection System Impact Study Agreement.

Simultaneously with the delivery of the Interconnection Feasibility Study to the Interconnection Customer, the ISO shall provide to the Interconnection Customer an Interconnection System Impact Study Agreement. The Interconnection System Impact Study Agreement shall provide that the Interconnection Customer shall compensate the ISO for the actual cost of the Interconnection System Impact Study. Within three (3) Business Days following the Interconnection Feasibility Study results meeting, the ISO in coordination with the applicable Participating TO(s) shall provide to the Interconnection Customer a signed System Impact Study Agreement which shall include a non-binding good faith estimate of the cost and timeframe for completing the Interconnection System Impact Study.

7.2 Execution of Interconnection System Impact Study Agreement.

The Interconnection Customer shall execute the Interconnection System Impact Study Agreement and deliver the executed Interconnection System Impact Study Agreement to the ISO no later than thirty (30) Calendar Days after its receipt along with a $50,000 deposit.

If the Interconnection Customer does not provide all such valid technical data, such as Attachment A to Part 1, when it delivers the Interconnection System Impact Study Agreement, the ISO shall notify the Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection System Impact Study Agreement and the Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed Interconnection System Impact Study Agreement or deposit.

If the Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting and the Interconnection Feasibility Study, a substitute Point of Interconnection identified by either the Interconnection Customer, the

ISO, or the applicable Participating TO(s), and acceptable to the others, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and re-studies shall be completed pursuant to LGIP Section 7.6 as applicable. If the ISO, applicable Participating TO(s)and the Interconnection Customer cannot agree that the results were unexpected, then the ISO will make a determination that the results were either expected or unexpected. For the purpose of this LGIP Section 7.2, if the applicable Participating TO(s), ISO and Interconnection Customer cannot agree on the substituted Point of Interconnection, then the Interconnection Customer may direct that the alternative as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to LGIP Section 3.5.4, shall be the substitute.

7.3 Scope of Interconnection System Impact Study.

The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the ISO Controlled Grid. The Interconnection System Impact Study will consider Base Cases as well as all generating facilities (and with respect to (iv) below, any identified Network Upgrades associated with such higher queued Interconnection Request) that, on the date the Interconnection System Impact Study is commenced: (i) are directly interconnected to the ISO Controlled Grid; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending request to interconnect to an Affected System; (iv) have a pending higher queued Interconnection Request to interconnect to the ISO Controlled Grid; and (v) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

The Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, a power flow analysis and a Deliverability Assessment as described in LGIP Sections 3.3.2 and 3.3.3. The Interconnection System Impact Study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested Interconnection Service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Interconnection System Impact Study will provide a list of facilities the ISO Controlled Grid that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost and cost responsibility and a non-binding good faith estimated time to construct and estimate of any other financial impacts (i.e., on Local Furnishing Bonds).

7.4 Interconnection System Impact Study Procedures.

The ISO shall coordinate the Interconnection System Impact Study with applicable Participating TO(s) and any Affected System that is affected by the Interconnection Request pursuant to LGIP Section 3.7 above. Existing studies shall be used to the extent practicable when conducting the Interconnection System Impact Study. The ISO will coordinate Base Case development with the applicable Participating TOs to ensure the Base Cases are accurately developed. The SO shall use Reasonable Efforts to complete a draft Interconnection System Impact Study within ninety (90) Calendar Days after the receipt of the executed Interconnection System Impact Study Agreement, study payment, and valid technical data. The ISO will share applicable sturdy results with the applicable Participating TO(s), for review and comment, and will incorporate comments into the study report. The ISO will issue a final Interconnection System Impact Study report to the Interconnection Customer within one hundred twenty (120) Calendar Days after the receipt of the executed Interconnection System Impact Study Agreement, study payment,

and valid technical data. If the ISO uses Clustering, the ISO shall use Reasonable Efforts to deliver a completed Interconnection System Impact Study within one hundred twenty (120) Calendar Days after the close of the Queue Cluster Window.

At the request of the Interconnection Customer or at any time the ISO determines that it will not meet the required time frame for completing the Interconnection System Impact Study, the ISO shall notify the Interconnection Customer as to the schedule status of the Interconnection System Impact Study. If the Interconnection System Impact Study cannot be completed within the time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required.

Upon request, the ISO shall provide the Interconnection Customer all supporting documentation, workpapers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the Interconnection System Impact Study, subject to confidentiality arrangements consistent with LGIP Section 13.1.

7.5 Meeting with the ISO and Participating TO(s).

Within ten (10) Business Days of providing an Interconnection System Impact Study report to the Interconnection Customer, the applicable Participating TO(s), the ISO and the Interconnection Customer shall meet to discuss the results of the Interconnection System Impact Study.

7.6 Re-Study.

If re-study of the Interconnection System Impact Study is required due to a higher queued project dropping out of the queue, a modification of a higher queued project subject to LGIP Section 4.4, or re-designation of the Point of Interconnection pursuant to LGIP Section 7.2, or any other effective change in information which necessitates a re-study, the ISO shall notify the Interconnection Customer in writing along with providing a description of the expected results of the re-study. Upon receipt of such notice, the Interconnection Customer shall provide the ISO within ten (10) Business Days either a written request that the ISO (i) terminate the study and withdraw the Interconnection Request; or (ii) continue the study. If the Interconnection Customer requests the ISO to continue the study, the Interconnection Customer shall pay the ISO an additional $10,000 deposit for the re-study along with providing written notice for the ISO to continue.

Such re-study shall take no longer than sixty (60) Calendar Days from the date the ISO receives the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. The ISO will share applicable study results within the applicable Participating TO(s) for review and comment, and will incorporate comments into the study report. The ISO will issue a final study report to the Interconnection Customer within eighty (80) Calendar Days following receipt of the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. If the Interconnection System Impact Study cannot be completed within that time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Any and all costs of re-study shall be borne by the Interconnection Customer being re-studied.

Section 8. Interconnection Facilities Study.

8.1 Interconnection Facilities Study Agreement.

Simultaneously with the delivery of the Interconnection System Impact Study report to the Interconnection Customer, the ISO shall provide to the Interconnection Customer a pro forma Interconnection Facilities Study Agreement. The pro forma Interconnection Facilities Study Agreement shall provide that the Interconnection Customer shall compensate the ISO for the actual cost of the Interconnection Facilities Study. Within ten (10) Business Days following the Interconnection System Impact Study results meeting, the ISO shall provide to the Interconnection Customer a signed Interconnection Facilities Study Agreement which shall include a non-binding good faith estimate of the cost and timeframe for completing the Interconnection Facilities Study. The Interconnection Customer shall execute the Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement to the ISO within thirty (30) Calendar Days after its receipt, together with the required technical data and the greater of $100,000 or the Interconnection Customer's portion of the estimated monthly cost of conducting the Interconnection Facilities Study.

8.1.1 For studies where the estimated cost exceeds $100,000, the ISO may invoice the Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study for the remaining balance of the estimated Interconnection Facilities Study cost. The Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. The ISO shall continue to hold the amounts on deposit until settlement of the final invoice.

8.2 Scope of Interconnection Facilities Study.

The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work, including the financial impacts (i.e., on Local Furnishing Bonds), if any, and schedule for effecting remedial measures that address such financial impacts, needed on the ISO Controlled Grid to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Customer's Interconnection Facilities to the ISO Controlled Grid. The Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Participating TO's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities.

8.3 Interconnection Facilities Study Procedures.

The ISO shall coordinate the Interconnection Facilities Study with the Participating TO(s) and any Affected System pursuant to LGIP Section 3.7 above. Existing studies shall be used to the extent practicable in conducting the Interconnection Facilities Study. The ISO, in collaboration with the Participating TO(s), shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to the Interconnection Customer. Prior to issuing draft study results to the Interconnection Customer, the ISO shall share study resultswi the Participating TO(s) for review and incorporate comments as necessary. Within the following number of days after receipt of an executed Interconnection Facilities Study Agreement, the ISO shall provide a draft Interconnection Facilities Study report to the Interconnection Customer: one hundred twenty (120) Calendar Days, with no more than a +/- 20 percent cost estimate contained

in the report; or two hundred ten (210) Calendar Days, if the Interconnection Customer requests a +/- 10 percent cost estimate. At the request of the Interconnection Customer or at any time the ISO determines that the required time frame for completing the Interconnection Facilities Study will not be met, the ISO shall notify the Interconnection Customer as to the schedule status of the Interconnection Facilities Study. If the Interconnection Facilities Study cannot be conducted and a draft Interconnection Facilities Study report cannot be issued within the time required, the ISO shall notify the Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required.

The Interconnection Customer shall, within thirty (30) Calendar Days after receipt of the draft report, either (i) provide written comments to the ISO, which the ISO, to the extent the comments are applicable, shall include in the final report, or (ii) provide a statement to the Participating TO and ISO that it will not provide comments. The ISO shall issue the final Interconnection Facilities Study report within fifteen (15) Business Days of receiving the Interconnection Customer's comments or promptly upon receiving the Interconnection Customer's statement that it will not provide comments. The ISO may reasonably extend such fifteen (15) Business Day period upon notice to the Interconnection Customer if the Interconnection Customer's comments require the applicable Participating TO(s) and/or ISO to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Study report. Upon request, the ISO shall provide the Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with LGIP Section 13.1.

8.4 Meeting with the ISO and Applicalbe Participating TO(s).

Within ten (10) Business Days of providing a draft Interconnection Facilities Study report to the Interconnection Customer, the applicable Participating TO(s), the ISO and the Interconnection Customer shall meet to discuss the results of the Interconnection Facilities Study. Within ten (10) Business Days of this meeting the Interconnection Customer shall make the election of which Delivery Network Upgrades identified in the Interconnection Facilities Study are to be installed. Any operating constraints on the Interconnection Customer's Generating Facility arising out of the Interconnection Customer's election not to install the Delivery Network Upgrades shall be as set forth in Article 9 and Part C of the LGIA.

8.5 Re-Study.

If re-study of the Interconnection Facilities Study is required due to a higher queued project dropping out of the queue or a modification of a higher queued project pursuant to LGIP Section 4.4, or any other effective change in information which necessitates a re-study, the ISO shall so notify the Interconnection Customer in writing. Upon receipt of such notice, the Interconnection Customer shall provide the ISO within ten (10) Business Days a written request that the ISO either (i) terminate the study and withdraw the Interconnection Request; or (ii) continue the study. If the Interconnection Customer requests the ISO to continue the study, the Interconnection Customer shall pay the ISO an additional $10,000 deposit for the re-study along with providing written notice for the ISO to continue.

Such re-study shall take no longer than sixty (60) Calendar Days from the date the ISO receives the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. The ISO shall share applicable study results with the applicable Participating TO(s) for review and comment and incorporate comments, as appropriate. The ISO will issue a final Interconnection Facilities Study report to the Interconnection Customer within eighty (80) Calendar Days following receipt of the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. If the Interconnection Facilities Study cannot be completed within that time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Any and all costs of re-study shall be borne by the Interconnection Customer being re-studied.

Section 9. Engineering & Procurement ("E&P") Agreement.

Prior to executing an LGIA, an Interconnection Customer may, in order to advance the implementation of its interconnection, request and the applicable Participating TO(s) shall offer the Interconnection Customer, an E&P Agreement that authorizes the applicable Participating TO(s) to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. However, the applicable Participating TO(s) shall not be obligated to offer an E&P Agreement if the Interconnection Customer is in Dispute Resolution as a result of an allegation that the Interconnection Customer has failed to meet any milestones or comply with any prerequisites specified in other parts of the LGIP. The E&P Agreement is an optional procedure and it will not alter the Interconnection Customer's Queue Position or In-Service Date. The E&P Agreement shall provide for the Interconnection Customer to pay the cost of all activities authorized by the Interconnection Customer and to make advance payments or provide other satisfactory security for such costs.

The Interconnection Customer shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If the Interconnection Customer withdraws its application for interconnection or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, the Interconnection Customer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, the applicable Participating TO(s) may elect: (i) to take title to the equipment, in which event the applicable Participating TO(s) shall refund the Interconnection Customer any amounts paid by Interconnection Customer for such equipment and shall pay the cost of delivery of such equipment, or (ii) to transfer title to and deliver such equipment to the Interconnection Customer, in which event the Interconnection Customer shall pay any unpaid balance and cost of delivery of such equipment.

Section 10. Optional Interconnection Study.

10.1 Optional Interconnection Study Agreement.

On or after the date when the Interconnection Customer receives Interconnection System Impact Study results, the Interconnection Customer may request, and the ISO shall conduct or cause to be conducted, a reasonable number of Optional Interconnection Studies. The request shall describe the assumptions that the Interconnection Customer wishes to be studied within the scope described in LGIP Section 10.2. Within five (5) Business Days after receipt of a request for an Optional Interconnection Study, the ISO shall provide to the Interconnection Customer an Optional Interconnection Study Agreement.

The Optional Interconnection Study Agreement shall: (i) specify the technical data that the Interconnection Customer must provide for each phase of the Optional Interconnection Study, (ii) specify the Interconnection Customer's assumptions as to which Interconnection Requests with higher Queue Positions will be excluded from the Optional Interconnection Study case and assumptions as to the type of interconnection

service for Interconnection Requests remaining in the Optional Interconnection Study case, and (iii) the ISO's estimate of the cost of the Optional Interconnection Study. To the extent known by the ISO, such estimate shall include any costs expected to be incurred by any Affected System whose participation is necessary to complete the Optional Interconnection Study. Notwithstanding the above, the ISO shall not be required as a result of an Optional Interconnection Study request to conduct any additional Interconnection Studies with respect to any other Interconnection Request.

The Interconnection Customer shall execute the Optional Interconnection Study Agreement within ten (10) Business Days of receipt and deliver the Optional Interconnection Study Agreement, the technical data and a $10,000 deposit to the ISO as applicable.

10.2 Scope of Optional Interconnection Study.

The Optional Interconnection Study will consist of a sensitivity analysis based on the assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement. The Optional Interconnection Study will also identify the Participating TOs' Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide transmission service or Interconnection Service based upon the results of the Optional Interconnection Study. The Optional Interconnection Study shall be performed solely for informational purposes. The ISO shall use Reasonable Efforts to coordinate the study with any Affected Systems that may be affected by the types of Interconnection Services that are being studied. The ISO shall utilize existing studies to the extent practicable in conducting the Optional Interconnection Study.

10.3 Optional Interconnection Study Procedures.

The ISO shall use Reasonable Efforts to have the Optional Interconnection Study completed within a mutually agreed upon time period specified within the Optional Interconnection Study Agreement. If the Optional Interconnection Study cannot be completed within such time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required. Any difference between the study payment and the actual cost of the study shall be paid to the ISO, as applicable, or refunded to the Interconnection Customer, as appropriate. Upon request, the ISO with support and cooperation of the applicable Participating TO(s) shall provide the Interconnection Customer supporting documentation and workpapers, and databases or data developed in the preparation of the Optional Interconnection Study, subject to confidentiality arrangements consistent with LGIP Sections 2.3 and 13.1.

Section 11. Standard Large Generator Interconnection Agreement (LGIA).

11.1 Tender.

11.1.1 Within thirty (30) Calendar Days after the ISO receives the Interconnection Customer's written comments, or notification of no comments, to the draft Interconnection Facilities Study report, the applicable Participating TO(s) and the ISO shall tender a draft LGIA, together with draft appendices. The draft LGIA shall be in the form of the FERC-approved standard form LGIA. The Interconnection Customer shall provide written comments, or notification of no comments, to the draft appendices to the applicable Participating TO(s) and the ISO within (30) Calendar Days of receipt.

11.1.2 Consistent with Section 3.4.4 and 11.1.1 of this LGIP, when the transmission system of a Participating TO, in which the Interconnection Point is not located, is affected, such Participating TO shall tender a separate agreement, in the form of the LGIA, as appropriately modified.

11.2 Negotiation.

Notwithstanding LGIP Section 11.1, at the request of the Interconnection Customer, the applicable Participating TO(s), and ISO shall begin negotiations with the Interconnection Customer concerning the appendices to the LGIA at any time after the Interconnection Customer executes the Interconnection Facilities Study Agreement. The applicable Participating TO(s) and ISO and the Interconnection Customer shall negotiate concerning any disputed provisions of the appendices to the draft LGIA for not more than sixty (60) Calendar Days after tender of the final Interconnection Facilities Study report. If the Interconnection Customer determines that negotiations are at an impasse, it may request termination of the negotiations at any time after tender of the draft LGIA pursuant to LGIP Section 11.1 and request submission of the unexecuted LGIA with FERC or initiate Dispute Resolution procedures pursuant to LGIP Section 13.5. If the Interconnection Customer requests termination of the negotiations, but within ninety (90) Calendar Days after issuance of the final Interconnection Facilities Study report fails to request either the filing of the unexecuted LGIA or initiate Dispute Resolution, it shall be deemed to have withdrawn its Interconnection Request. Unless otherwise agreed by the Parties, if the Interconnection Customer has not executed and returned the LGIA, requested filing of an unexecuted LGIA, or initiated Dispute Resolution procedures pursuant to LGIP Section 13.5 within ninety (90) Calendar Days after issuance of the final Interconnection Facilities Study report, it shall be deemed to have withdrawn its Interconnection Request. The applicable Participating TO(s) and ISO shall provide to the Interconnection Customer a final LGIA within fifteen (15) Business Days after the completion of the negotiation process.

11.3 Execution and Filing.

At the time that the Interconnection Customer either returns the executed LGIA or requests the filing of an unexecuted LGIA as specified below, the Interconnection Customer shall provide the applicable Participating TO(s) and ISO (A) reasonable evidence of continued Site Control or (B) posting to the applicable Participating TO(s) of $250,000, non-refundable additional security, which shall be applied toward future construction costs. At the same time, the Interconnection Customer also shall provide reasonable evidence that one or more of the following milestones in the development of the Large Generating Facility, at the Interconnection Customer election, has been achieved: (i) the execution of a contract for the supply or transportation of fuel to the Large Generating Facility; (ii) the execution of a contract for the supply of cooling water to the Large Generating Facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Large Generating Facility; (iv) execution of a contract for the sale of electric energy or capacity from the Large Generating Facility; or (v) application for an air, water, or land use permit.

The Interconnection Customer shall either: (i) execute four originals of the tendered LGIA and return one to the applicable Participating TO(s) and two to the ISO; or (ii) request in writing that the applicable Participating TO(s) and ISO file with FERC an LGIA in unexecuted form. As soon as practicable, but not later than ten (10) Business Days after receiving either the executed originals of the tendered LGIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or the request to file an unexecuted LGIA, the applicable Participating TO(s) and ISO shall file the LGIA with FERC, as necessary, together with an explanation of any matters as to which the Interconnection Customer and the applicable Participating TO(s) or ISO disagree and support for the costs that the applicable Participating TO(s) propose to charge to the Interconnection Customer under the LGIA. An unexecuted LGIA should contain terms and conditions deemed appropriate by the applicable Participating TO(s) and ISO for the Interconnection Request. If the Parties agree to proceed with design, procurement, and

construction of facilities and upgrades under the agreed-upon terms of the unexecuted LGIA, they may proceed pending FERC action.

11.4 Commencement of Interconnection Activities.

If the Interconnection Customer executes the final LGIA, the applicable Participating TO(s), ISO and the Interconnection Customer shall perform their respective obligations in accordance with the terms of the LGIA, subject to modification by FERC. Upon submission of an unexecuted LGIA, the Interconnection Customer, applicable Participating TO(s) and ISO may proceed to comply with the unexecuted LGIA, pending FERC action.

11.5 Interconnection Customer to Meet Requirements of the Participating TO's Interconnection Handbook.

The Interconnection Customer's Interconnection Facilities shall be designed, constructed, operated and maintained in accordance with the applicable Participating TO's Interconnection Handbook.

Section 12. Construction of Participating TO's Interconnection Facilities and Network Upgrades.

12.1 Schedule.

The applicable Participating TO(s) and the Interconnection Customer shall negotiate in good faith concerning a schedule for the construction of the applicable Participating TO's Interconnection Facilities and the Network Upgrades.

12.2 Construction Sequencing.

12.2.1 General.

In general, the in-service date in the LGIA of an Interconnection Customer seeking interconnection to the ISO Controlled Grid will determine the sequence of construction of Network Upgrades.

12.2.2 Advance Construction of Network Upgrades that are an Obligation of an Entity other than the Interconnection Customer.

An Interconnection Customer with an LGIA, in order to maintain its In-Service Date, may request that the applicable Participating TO(s) advance to the extent necessary the completion of Network Upgrades that: (i) were assumed in the Interconnection Studies for such Interconnection Customer, (ii) are necessary to support such In-Service Date, and (iii) would otherwise not be completed, pursuant to a contractual obligation of an entity other than the Interconnection Customer that is seeking interconnection to the ISO Controlled Grid, in time to support such In-Service Date. Upon such request, the applicable Participating TO(s) will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that the Interconnection Customer commits to pay the applicable Participating TO(s): (i) any associated expediting costs and (ii) the cost of such Network Upgrades.

The applicable Participating TO(s) will refund to the Interconnection Customer both the expediting costs and the cost of Network Upgrades, in accordance with Article 11.4 of the LGIA. Consequently, the entity with a contractual obligation to construct such Network Upgrades shall be obligated to pay only that portion of the costs of the Network Upgrades that the applicable Participating TO(s) have not refunded to the Interconnection Customer. Payment by that entity shall be due on the date that it would have been due had there been no request for advance construction. The applicable Participating TO(s) shall forward to the Interconnection Customer the amount paid by the entity with a contractual obligation to construct the Network Upgrades as payment in full for the outstanding balance owed to the Interconnection Customer. The applicable Participating TO(s) then shall refund to that entity the amount that it paid for the Network Upgrades, in accordance with Article 11.4 of the LGIA.

12.2.3 Advancing Construction of Network Upgrades that are Part of an Expansion Plan of the Participating TO.

An Interconnection Customer with an LGIA, in order to maintain its in-service date as specified in the LGIA, may request that the applicable Participating TO(s) advance to the extent necessary the completion of Network Upgrades that: (i) are necessary to support such in-service date and (ii) would otherwise not be completed, pursuant to an expansion plan of the applicable Participating TO(s), in time to support such in-service date. Upon such request, the applicable Participating TO(s) will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that the Interconnection Customer commits to pay the applicable Participating TO(s) any associated expediting costs. The Interconnection Customer shall be entitled to refunds, if any, in accordance with this LGIP and the LGIA, for any expediting costs paid.

12.2.4 Amended Interconnection Study.

An Interconnection Study will be amended, as needed, to determine the facilities necessary to support the requested in-service date as specified in the LGIA. This amended study will include those transmission facilities, Large Generating Facilities and any other generating facilities that are expected to be in service on or before the requested in-service date. If an amendment to an Interconnection Study is required, the ISO shall notify the Interconnection Customer in writing. Upon receipt of such notice, the Interconnection Customer shall provide the ISO within ten (10) Business Days a written request that the ISO either (i) terminate the amended study and withdraw the Interconnection Customer's Interconnection Request or (ii) continue with the amended study. If the Interconnection Customer requests the ISO to continue with the amended study, the Interconnection Customer shall pay the ISO an additional $10,000 deposit for the amended study along with providing written notice for the ISO to continue. Such amended study shall take no longer than sixty (60) Calendar Days from the date the ISO receives the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. The ISO shall share applicable study results with the applicable Participating TO(s) for review and comment, and incorporate comments and issue a final study to the Interconnection Customer within eighty (80) Calendar Days from the date of the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. If the amended Interconnection Study cannot be completed within that time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Any and all costs of the amended study shall be borne by the Interconnection Customer being re-studied.

Section 13. Miscellaneous.

13.1 Confidentiality.

Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by any of the Parties to the other Parties prior to the execution of an LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Parties receiving the information that the information is confidential.

If requested by any Party, the other Parties shall provide in writing, the basis for asserting that the information referred to in this Section warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

The confidentiality provisions of this LGIP are limited to information provided pursuant to this LGIP.

13.1.1 Scope.

Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or breach of the LGIA; or (6) is required, in accordance with LGIP Section 13.1.6, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under the LGIP. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Parties that it no longer is confidential.

13.1.2 Release of Confidential Information.

No Party shall release or disclose Confidential Information to any other person, except to its employees, consultants, Affiliates (limited by FERC's Standards of Conduct requirements set forth in Part 358 of FERC's Regulations, 18 C.F.R. 358), or to parties who may be or considering providing financing to or equity participation with the Interconnection Customer, or to potential purchasers or assignees of the Interconnection Customer, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this LGIP Section 13.1 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this LGIP Section 13.1.

13.1.3 Rights.

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Parties. The disclosure by each Party to the other Parties of Confidential Information shall not be deemed a waiver by a Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

13.1.4 No Warranties.

By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to the other Parties nor to enter into any further agreements or proceed with any other relationship or joint venture.

13.1.5 Standard of Care.

Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Parties under these procedures or its regulatory requirements.

13.1.6 Order of Disclosure.

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires any Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Parties with prompt notice of such request(s) or requirement(s) so that the other Parties may seek an appropriate protective order or waive compliance with the terms of the LGIP. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

13.1.7 Remedies.

Monetary damages are inadequate to compensate a Party for another Party's breach of its obligations under this LGIP Section 13.1. Each Party accordingly agrees that the other Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party breaches or threatens to breach its obligations under this LGIP Section 13.1, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the breach of this LGIP Section 13.1, but shall be in addition to all other remedies available at law or in equity. Further, the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this LGIP Section 13.1.

13.1.8 Disclosure to FERC, its Staff, or a State.

Notwithstanding anything in this Section 13.1 to the contrary, and pursuant to 18 C.F.R. section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to the LGIP, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties prior to the release of the Confidential

Information to FERC or its staff. The Party shall notify the other applicable Parties when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, consistent with applicable state rules and regulations.

13.1.9 Subject to the exception in LGIP Section 13.1.8, any Confidential Information shall not be disclosed by the other Parties to any person not employed or retained by the other Parties, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Parties, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIP or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a subregional, regional or national reliability organization or planning group. The Party asserting confidentiality shall notify the other Parties in writing of the information it claims is confidential. Prior to any disclosures of another Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

13.1.10 This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a breach of this provision).

13.1.11 The Participating TO or ISO shall, at the Interconnection Customer's election, destroy, in a confidential manner, or return the Confidential Information provided at the time of Confidential Information is no longer needed.

13.2 Delegation of Responsibility.

The ISO and the participating TOs may use the services of subcontractors as deemed appropriate to perform their obligations under this LGIP. The applicable Participating TO or ISO shall remain primarily liable to the Interconnection Customer for the performance of its respective subcontractors and compliance with its obligations of this LGIP. The subcontractor shall keep all information provided confidential and shall use such information solely for the performance of such obligation for which it was provided and no other purpose.

13.3 Obligation for Study Costs.

The ISO shall charge and the Interconnection Customer shall pay the actual costs of the Interconnection Studies. Any difference between the study deposit and the actual cost of the applicable Interconnection Study shall be paid by or refunded to the Interconnection Customer. Any invoices for Interconnection Studies shall include a detailed and itemized accounting of the cost of each Interconnection Study. The Interconnection Customer shall pay any such undisputed costs within thirty (30) Calendar Days of receipt of an invoice therefor. The ISO shall not be obligated to continue to have any studies conducted unless the Interconnection Customer has paid all undisputed amounts in compliance herewith. In the event an Interconnection Study is performed by the ISO, or is performed by a third party consultant pursuant to LGIP Section 13.4, the Interconnection Customer shall pay only the costs of those activities performed by the Participating TO to adequately review or validate that Interconnection Study.

13.4 Third Parties Performing Studies.

If (i) at the time of the signing of an Interconnection Study agreement there is disagreement as to the estimated time to complete an Interconnection Study, (ii) the Interconnection Customer receives notice pursuant to LGIP Sections 6.3, 7.4 or 8.3 that an Interconnection Study cannot be completed within the applicable timeframe for such Interconnection Study, or (iii) the Interconnection Customer receives neither the Interconnection Study nor a notice under LGIP Sections 6.3, 7.4 or 8.3 within the applicable timeframe for such Interconnection Study, then the Interconnection Customer may request that the ISO: (1) utilize a third party consultant reasonably acceptable to the Interconnection Customer, the ISO, and the Participating TO or (2) utilize the applicable Participating TO(s) to perform such Interconnection Study under the direction of the ISO. At other times, the Participating TO or ISO may also utilize a third party consultant to perform such Interconnection Study, either in response to a general request of the Interconnection Customer, or on its own volition.

In all cases, use of a third party consultant shall be in accord with Article 26 of the LGIA (Subcontractors) and limited to situations where the ISO determines that doing so will help maintain or accelerate the study process for the Interconnection Customer's pending Interconnection Request and not interfere with the ISO's or Participating TO's progress on Interconnection Studies for other pending Interconnection Requests. In cases where the Interconnection Customer requests use of a third party consultant to perform such Interconnection Study, the Interconnection Customer and the Participating TO or ISO shall negotiate all of the pertinent terms and conditions, including reimbursement arrangements and the estimated study completion date and study review deadline. The applicable Participating TO(s) and the ISO shall convey all workpapers, data bases, study results and all other supporting documentation prepared to date with respect to the Interconnection Request as soon as practicable upon the Interconnection Customer's request subject to the confidentiality provision in LGIP Section 13.1. In any case, such third party contract may be entered into with the Interconnection Customer, the applicable Participating TO(s), or the ISO at the Participating TO's or ISO's discretion. If the Interconnection Customer enters into a third party Interconnection Study agreement, the Interconnection Customer shall provide the Interconnection Study to the ISO and the Participating TO for review, and such third party Interconnection Study agreement shall provide for reimbursement by the Interconnection Customer of the ISO's and Participating TO's actual cost of participating in and reviewing the Interconnection Study. In the case of (iii) the Interconnection Customer maintains its right to submit a claim to Dispute Resolution to recover the costs of such third party study. Such third party consultant shall be required to comply with this LGIP, Article 26 of the LGIA (Subcontractors), the ISO Tariff, and the relevant Participating TO's TO Tariff as would apply if the Participating TO or ISO were to conduct the Interconnection Study and shall use the information provided to it solely for purposes of performing such services and for no other purposes. The applicable Participating TO(s) and the ISO shall cooperate with such third party consultant and the Interconnection Customer to complete and issue the Interconnection Study in the shortest reasonable time.

13.5 Disputes.

All disputes arising out of or in connection with this LGIP whereby relief is sought by or from the ISO shall be settled in accordance with the ISO ADR Procedures. Disputes arising out of or in connection with this LGIP not subject to the ISO ADR Procedures shall be resolved as follows:

13.5.1 Submission.

In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with the LGIA, the LGIP, or their performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of the LGIA and LGIP.

13.5.2 External Arbitration Procedures.

Any arbitration initiated under these procedures shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this LGIP Section 13, the terms of this LGIP Section 13 shall prevail.

13.5.3 Arbitration Decisions.

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the LGIA and LGIP and shall have no power to modify or change any provision of the LGIA and LGIP in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

13.5.4 Costs.

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

13.6 Local Furnishing Bonds.

13.6.1 Participating TOs That Own Facilities Financed by Local Furnishing Bonds.

This provision is applicable only to a Participating TO that has financed facilities for the local furnishing of electric energy with Local Furnishing Bonds. Notwithstanding any other provisions of this LGIP, the Participating TO and the ISO shall not be required to provide Interconnection Service to the Interconnection Customer pursuant to this LGIP and the LGIA if the provision of such Interconnection Service would jeopardize the tax-exempt status of any Local Furnishing Bond(s) issued for the benefit of the Participating TO.

13.6.2 Alternative Procedures for Requesting Interconnection Service.

If a Participating TO determines that the provision of Interconnection Service requested by the Interconnection Customer would jeopardize the tax-exempt status of any Local Furnishing Bond(s) issued for the benefit of the Participating TO, it shall advise the Interconnection Customer and the ISO within (30) Calendar Days of receipt of the Interconnection Request.

The Interconnection Customer thereafter may renew its request for the same interconnection Service by tendering an application under Section 211 of the Federal Power Act, in which case the Participating TO, within ten (10) Calendar Days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, and the ISO and Participating TO shall provide the requested Interconnection Service pursuant to the terms and conditions set forth in this LGIP and the LGIA.

PART 1 to LGIP
INTERCONNECTION REQUEST

Provide three copies of this completed form pursuant to Section 7 below.

1. The undersigned Interconnection Customer submits this request to interconnect its Large Generating Facility with the ISO Controlled Grid pursuant to the ISO Tariff.

2. This Interconnection Request is for (check one):
   _____ A proposed new Large Generating Facility.
   _____ An increase in the generating capacity or a Material Modification of an existing Generating Facility.

4. The Interconnection Customer provides the following information:

   a. Address or location, including the county, of the proposed new Large Generating Facility site or, in the case of an existing Generating Facility, the name and specific location, including the county, of the existing Generating Facility;

   b. Maximum megawatt electrical output of the proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of an existing Generating Facility;

   c. Type of project (i.e., gas turbine, hydro, wind, etc.) and general description of the equipment configuration;

   d. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by day, month, and year and term of service;

   e. Name, address, telephone number, and e-mail address of the Interconnection Customer's contact person;

   f. Approximate location of the proposed Point of Interconnection; and

   g. Interconnection Customer Data (set forth in Attachment A)

5. Applicable deposit amount as specified in the LGIP.

6. Evidence of Site Control as specified in the LGIP and name(s), address(es) and contact information of site owner(s) (check one):

   ____ Is attached to this Interconnection Request
   ____ Will be provided at a later date in accordance with this LGIP

7. This Interconnection Request shall be submitted to the representative indicated below:

   New Resource Interconnection
   California ISO
   P.O. Box 639014
   Folsom, CA 95763-9014

   Overnight address: 151 Blue Ravine Road, Folsom, CA 95630

8. Representative of the Interconnection Customer to contact:

[To be completed by the Interconnection Customer]

9. This Interconnection Request is submitted by:

Name of the Interconnection Customer:

By (signature):

Name (type or print):

Title:

Date

Attachment A
To Part 1
Interconnection Request

LARGE GENERATING FACILITY DATA

Provide three copies of this completed form pursuant to Section 7 of Part 1.

1. Provide two original prints and one reproducible copy (no larger than 36" x 24") of the following:

A. Site drawing to scale, showing generator location and point of interconnection with the ISO Controlled Grid.
B. Single-line diagram showing applicable equipment such as generating units, step-up transformers, auxiliary transformers, switches/disconnects of the proposed interconnection, including the required protection devices and circuit breakers. For wind generator farms, the one line diagram should include the distribution lines connecting the various groups of generating units, the generator capacitor banks, the step up transformers, the distribution lines, and the substation transformers and capacitor banks at the point of interconnection with the utility.

2. Generating Facility Information

A) Total Generating Facility rated output (kW): _____
B) Generating Facility auxiliary load (kW): _____
C) Project net capacity (kW): _____
D) Standby load when Generating Facility is off-line (kW): _____

E) Number of Generating Units: _____
(Please repeat the following items for each generator)
F) Individual generator rated output (kW for each unit): _____
G) Manufacturer: _____
H) Year Manufactured: _____
I) Nominal Terminal Voltage: _____
J) Rated Power Factor (%): _____
K) Type (Induction, Synchronous, D.C. with Inverter): _____
L) Phase (3 phase or single phase): _____
M) Connection (Delta, Grounded WYE, Ungrounded WYE, impedance grounded): _____
N) Generator Voltage Regulation Range: _____
O) Generator Power Factor Regulation Range: _____
P) For combined cycle plants, specify the plant output for an outage of the steam turbine or an outage of a single combustion turbine:

3. Synchronous Generator – General Information:
(Please repeat the following for each generator)

A. Rated Generator speed (rpm): _____
B. Rated MVA: _____
C. Rated Generator Power Factor: _____
D. Generator Efficiency at Rated Load (%): _____
E. Moment of Inertia (including prime mover): _____
F. Inertia Time Constant (on machine base) H: _____ sec or MJ/MVA
G. SCR (Short-Circuit Ratio - the ratio of the field current required for rated open-circuit

voltage to the field current required for rated short-circuit current):
_____

H. Please attach generator reactive capability curves.
I. Rated Hydrogen Cooling Pressure in psig (Steam Units only): _____
J. Please attach a plot of generator terminal voltage versus field current that shows the air gap line, the open-circuit saturation curve, and the saturation curve at full load and rated power factor.

4. Excitation System Information
(Please repeat the following for each generator)

A. Indicate the Manufacturer _____ and Type _____of excitation system used for the generator. For exciter type, please choose from 1 to 8 below or describe the specific excitation system.

1) Rotating DC commutator exciter with continuously acting regulator. The regulator power source is independent of the generator terminal voltage and current.

2) Rotating DC commentator exciter with continuously acting regulator. The regulator power source is bus fed from the generator terminal voltage.

3) Rotating DC commutator exciter with non-continuously acting regulator (i.e., regulator adjustments are made in discrete increments).

4) Rotating AC Alternator Exciter with non-controlled (diode) rectifiers. The regulator power source is independent of the generator terminal voltage and current (not bus-fed).

5) Rotating AC Alternator Exciter with controlled (thyristor) rectifiers. The regulator power source is fed from the exciter output voltage.

6) Rotating AC Alternator Exciter with controlled (thyristor) rectifiers.

7) Static Exciter with controlled (thyristor) rectifiers. The regulator power source is bus-fed from the generator terminal voltage.

8) Static Exciter with controlled (thyristor) rectifiers. The regulator power source is bus-fed from a combination of generator terminal voltage and current (compound-source controlled rectifiers system.

B. Attach a copy of the block diagram of the excitation system from its instruction manual. The diagram should show the input, output, and all feedback loops of the excitation system.

C. Excitation system response ratio (ASA): _____
D. Full load rated exciter output voltage: _____
E. Maximum exciter output voltage (ceiling voltage): _____
F. Other comments regarding the excitation system?
_____
_____
_____

5. Power System Stabilizer Information.

(Please repeat the following for each generator. All new generators are required to install PSS unless an exemption has been obtained from WECC. Such an exemption can be obtained for units that do not have suitable excitation systems.)

A. Manufacturer: _____

B. Is the PSS digital or analog? _____

C. Note the input signal source for the PSS?
_____ Bus frequency _____ Shaft speed _____ Bus Voltage
_____ Other (specify source)

D. Please attach a copy of a block diagram of the PSS from the PSS Instruction Manual and the correspondence between dial settings and the time constants or PSS gain.

E: Other comments regarding the PSS?
_____
_____
_____

6. Turbine-Governor Information

(Please repeat the following for each generator)

Please complete Part A for steam, gas or combined-cycle turbines, Part B for hydro turbines, and Part C for both.

A. Steam, gas or combined-cycle turbines:

1.) List type of unit (Steam, Gas, or Combined-cycle):_____
2.) If steam or combined-cycle, does the turbine system have a reheat process (i.e., both high and low pressure turbines)? _____
3.) If steam with reheat process, or if combined-cycle, indicate in the space provided, the percent of full load power produced by each turbine:
Low pressure turbine or gas turbine: _____%
High pressure turbine or steam turbine: _____%

B. Hydro turbines:

1.) Turbine efficiency at rated load: _____%
2.) Length of penstock: _____ft
3.) Average cross-sectional area of the penstock: _____ft2
4.) Typical maximum head (vertical distance from the bottom of the penstock, at the gate, to the water level): _____ft
5.) Is the water supply run-of-the-river or reservoir: _____
6.) Water flow rate at the typical maximum head: _____ft3/sec
7.) Average energy rate: _____kW-hrs/acre-ft
8.) Estimated yearly energy production: _____kW-hrs

C. Complete this section for each machine, independent of the turbine type.

1.) Turbine manufacturer: _____
2.) Maximum turbine power output: _____MW
3.) Minimum turbine power output (while on line): _____MW
4.) Governor information:
a: Droop setting (speed regulation): _____
b: Is the governor mechanical-hydraulic or electro-hydraulic (Electro-hydraulic governors have an electronic speed sensor and transducer.)? _____

c: Other comments regarding the turbine governor system?
_____
_____
_____
_____

7. Synchronous Generator and Associated Equipment – Dynamic Models:

For each generator, governor, exciter and power system stabilizer, select the appropriate dynamic model from the General Electric PSLF Program Manual and provide the required input data. The manual is available on the GE website at www.gepower.com. Select the following links within the website: 1) Our Businesses, 2) GE Power Systems, 3) Energy Consulting, 4) GE PSLF Software, 5) GE PSLF User's Manual.

There are links within the GE PSLF User's Manual to detailed descriptions of specific models, a definition of each parameter, a list of the output channels, explanatory notes, and a control system block diagram. The block diagrams are also available on the Ca-ISO website.

If you require assistance in developing the models, we suggest you contact General Electric. Accurate models are important to obtain accurate study results. Costs associated with any changes in facility requirements that are due to differences between model data provided by the generation developer and the actual generator test data, may be the responsibility of the generation developer.

8. Induction Generator Data:

A. Rated Generator Power Factor at rated load: _____
B. Moment of Inertia (including prime mover): _____
C. Do you wish reclose blocking? Yes ___, No ___
Note: Sufficient capacitance may be on the line now, or in the future, and the generator may self-excite unexpectedly.

9. Generator Short Circuit Data

For each generator, provide the following reactances expressed in p.u. on the generator base:

- X"1 – positive sequence subtransient reactance: _____
- X"2 – negative sequence subtransient reactance: _____
- X"0 – zero sequence subtransient reactance: _____

Generator Grounding:

A. _____ Solidly grounded
B. _____ Grounded through an impedance

Impedance value in p.u on generator base. R:_____p.u.
X:_____p.u.
C. _____ Ungrounded

10. Step-Up Transformer Data

For each step-up transformer, fill out the data form provided in Table 1.

11. Line Data

There is no need to provide data for new lines that are to be planned by the Participating TO. However, for transmission lines that are to be planned by the generation developer, please provide the following information:

Nominal Voltage: _____
Line Length (miles): _____
Line termination Points: _____
Conductor Type: _____ Size: _____
If bundled. Number per phase: _____, Bundle spacing: _____in.
Phase Configuration. Vertical: _____, Horizontal: _____
Phase Spacing (ft): A-B: _____, B-C: _____, C-A: _____
Distance of lowest conductor to Ground: _____ft
Ground Wire Type: _____ Size: _____ Distance to Ground: _____ft
Attach Tower Configuration Diagram
Summer line ratings in amperes (normal and emergency) _____
Resistance (R): _____ p.u.**
Reactance: (X): _____ p.u**
Line Charging (B/2): _____ p.u**
** On 100-MVA and nominal line voltage (kV) Base

12. Wind Generators

Number of generators to be interconnected pursuant to this Interconnection Request: ____

Elevation: _____ _____ Single Phase _____ Three Phase

Inverter manufacturer, model name, number, and version:
_____

List of adjustable setpoints for the protective equipment or software:
_____

Field Volts: _____
Field Amperes: _____
Motoring Power (kW): _____
Neutral Grounding Resistor (If Applicable): _____
I_2^2t or K (Heating Time Constant): _____
Rotor Resistance: _____
Stator Resistance: _____
Stator Reactance: _____
Rotor Reactance: _____
Magnetizing Reactance: _____
Short Circuit Reactance: _____
Exciting Current: _____
Temperature Rise: _____
Frame Size: _____
Design Letter: _____
Reactive Power Required In Vars (No Load): _____
Reactive Power Required In Vars (Full Load): _____
Total Rotating Inertia, H: _____ Per Unit on KVA Base

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device then they shall be provided and discussed at Scoping Meeting.

TABLE 1

TRANSFORMER DATA

UNIT_____

NUMBER OF TRANSFORMERS_____ PHASE _____

RATED KVA	H Winding	X Winding	Y Winding
Connection (Delta, Wye, Gnd.)	_____	_____	_____
55 C Rise	_____	_____	_____
65 C Rise	_____	_____	_____
RATED VOLTAGE	_____	_____	_____
BIL	_____	_____	_____
AVAILABLE TAPS (planned or existing)	_____	_____	_____
LOAD TAP CHANGER?	_____	_____	_____
TAP SETTINGS	_____	_____	_____

COOLING TYPE : OA_____ OA/FA_____ OA/FA/FA_____ OA/FOA_____

IMPEDANCE	H-X	H-Y	X-Y
Percent	_____	_____	_____
MVA Base	_____	_____	_____
Tested Taps	_____	_____	_____

WINDING RESISTANCE	H	X	Y
Ohms	_____	_____	_____

CURRENT TRANSFORMER RATIOS

H_____ X_____ Y_____ N_____

PERCENT EXCITING CURRENT 100 % Voltage; _____ 110% Voltage_____

Supply copy of nameplate and manufacture's test report when available

Part 2 TO LGIP

PART 2 INTERCONNECTION PROCEDURES FOR A WIND GENERATING PLANT

PART 2 to LGIP
INTERCONNECTION PROCEDURES FOR A WIND GENERATING PLANT

Part 2 sets forth procedures specific to a wind generating plant. All other requirements of this LGIP continue to apply to wind generating plant interconnections.

A. Special Procedures Applicable to Wind Generators

The wind plant Interconnection Customer, in completing the Interconnection Request required by section 3.1 of this LGIP, may provide to the ISO a set of preliminary electrical design specifications depicting the wind plant as a single equivalent generator. Upon satisfying these and other applicable Interconnection Request conditions, the wind plant may enter the queue and receive the Base Case data as provided for in this LGIP.

No later than six months after submitting an Interconnection Request completed in this manner, the wind plant Interconnection Customer must submit completed detailed electrical design specifications and other data (including collector system layout data) needed to allow the ISO to complete the Interconnection Study.

INTERCONNECTION FEASIBILITY STUDY AGREEMENT

THIS AGREEMENT is made and entered into this___day of _____, 20___by and between _____, a _____ organized and existing under the laws of the State of _____, ("Interconnection Customer,") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, (“ISO"). The Interconnection Customer and the ISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated _____ ; and

WHEREAS, the Interconnection Customer desires to interconnect the Large Generating Facility with the ISO Controlled Grid; and

WHEREAS, the Interconnection Customer has requested the ISO to conduct or cause to be performed an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Large Generating Facility.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the ISO's FERC-approved Standard Large Generation Interconnection Procedures (“LGIP”) or the Master Definitions Supplement, Appendix A to the ISO Tariff, as applicable.

2.0 The Interconnection Customer elects and the ISO shall conduct or cause to be performed an Interconnection Feasibility Study consistent with the LGIP in accordance with the ISO Tariff.

3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection Feasibility Study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the Scoping Meeting. The ISO reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with Section 3.5.4 of the LGIP. If, after the designation of the Point of Interconnection pursuant to Section 3.5.4 of the LGIP, the Interconnection Customer modifies its Interconnection Request pursuant to Section 4.4, the time to complete the Interconnection Feasibility Study may be extended.

5.0 The Interconnection Feasibility Study report shall provide the following information:

- preliminary identification of any circuit breaker short circuit capability limits exceeded on the Participating TO's electric system or the ISO Controlled Grid as a result of the interconnection;

- preliminary identification of any thermal overload or voltage limit violations on the Participating TO's electric system or the ISO Controlled Grid resulting from the interconnection;

- preliminary description and non-binding good faith estimate of cost and cost responsibility for and time for construction of the Participating TO's facilities required to interconnect the Large Generating Facility to the Participating TO's electric system or the ISO Controlled Grid and to address the identified short circuit and power flow issues;

- preliminary identification of financial impacts, if any, on Local Furnishing Bonds; and

- expected results in the Interconnection System Impact Study.

6.0 In addition to the deposit(s) paid by the Interconnection Customer pursuant to Section 3.5.1 of the LGIP, the Interconnection Customer shall provide a deposit of $10,000 for the performance of the Interconnection Feasibility Study.

Following the issuance of the Interconnection Feasibility Study to the Interconnection Customer the ISO shall charge and the Interconnection Customer shall pay the actual costs of the Interconnection Feasibility Study, inclusive of any re-studies and amendments to the Interconnection Feasibility Study, pursuant to Section 9 of this Agreement.

Any difference between the deposits made toward the Interconnection Feasibility Study, amendments and re-studies to the Interconnection Feasibility Study, and the actual cost of the study shall be paid by or refunded to the Interconnection Customer, as appropriate in accordance with Section 13.3 of the LGIP.

7.0 Pursuant to Section 3.7 of the LGIP, the ISO will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems. The ISO may provide a copy of the Interconnection Feasibility Study results to an Affected System Operator and the Western Electricity Coordinating Council. Requests for review and input from Affected System Operators or the Western Electricity Coordinating Council may arrive at any time prior to interconnection, and a revision of the Interconnection Feasibility Study or re-study may be required in such event.

8.0 Substantial portions of technical data and assumptions used to perform the Interconnection Feasibility Study, such as system conditions, existing and planned generation, and unit modeling, may change after the ISO provides the Interconnection Feasibility Study results to the Interconnection Customer.

Study results will reflect available data at the time the ISO provides the Interconnection Feasibility Study to the Interconnection Customer. The ISO shall not be responsible for any additional costs, including, without limitation, costs of new or additional facilities, system upgrades, or schedule changes, that may be incurred by the Interconnection Customer as a result of changes in such data and assumptions.

9.0 In the event that a re-study or amendment of the Interconnection Feasibility Study is required, the ISO shall provide notification of the need for such re-study or amendment, and the Interconnection Customer shall provide direction as to whether to proceed with the re-study or amendment and any associated deposit payment pursuant to Section 6.4 or Section 12.2.4 of the LGIP, as applicable.

10.0 The ISO shall maintain records and accounts of all costs incurred in performing the Interconnection Feasibility Study, inclusive of any re-studies or amendments thereto, in sufficient detail to allow verification of all costs incurred, including associated overheads. The Interconnection Customer shall have the right, upon reasonable notice, within a reasonable time following receipt of the final cost report associated with this Interconnection Feasibility Study at the ISO's offices and at its own expense, to audit the ISO's records as necessary and as appropriate in order to verify costs incurred by the ISO. Any audit requested by the Interconnection Customer shall be completed, and written notice of any audit dispute provided to the ISO, within one hundred eighty (180) Calendar Days following receipt by the Interconnection Customer of the ISO's notification of the final costs of the Interconnection Feasibility Study, inclusive of any re-study or amendment thereto.

11.0 In accordance with Section 3.8 of the LGIP, the Interconnection Customer may withdraw its Interconnection Request at any time by written notice to the ISO. Upon receipt of such notice, this Agreement shall terminate.

12.0 Pursuant to Section 6.1 of the LGIP, this Agreement shall become effective upon the date the fully executed Agreement and deposit specified in Section 6 of this Agreement are received by the ISO. If the ISO does not receive the fully executed Agreement and payment pursuant to Section 6.1 of the LGIP, then the Interconnection Request will be deemed withdrawn upon the Interconnection Customer's receipt of written notice by the ISO pursuant to Section 3.8 of the LGIP.

13.0 Miscellaneous.

13.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Interconnection Feasibility Study Agreement, shall be resolved in accordance with Section 13.5 of the LGIP

13.2 Confidentiality. Confidential Information shall be treated in accordance with Section 13.1 of the LGIP.

13.3 Binding Effect. This Interconnection Feasibility Study Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

13.4 Conflicts. In the event of a conflict between the body of this Interconnection Feasibility Study Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Interconnection Feasibility Study Agreement shall prevail and be deemed the final intent of the Parties.

13.5 Rules of Interpretation. This Interconnection Feasibility Study Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Interconnection Feasibility Study Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Section, or other provision

hereof or thereof); (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article or Section of this Interconnection Feasibility Study Agreement or such Appendix to this Interconnection Feasibility Study Agreement, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Interconnection Feasibility Study Agreement as a whole and not to any particular Article; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

13.6 Entire Agreement. This Interconnection Feasibility Study Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Interconnection Feasibility Study Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this Interconnection Feasibility Study Agreement.

13.7 No Third Party Beneficiaries. This Interconnection Feasibility Study Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

13.8 Waiver. The failure of a Party to this Interconnection Feasibility Study Agreement to insist, on any occasion, upon strict performance of any provision of this Interconnection Feasibility Study Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Interconnection Feasibility Study Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Interconnection Feasibility Study Agreement. Termination or default of this Interconnection Feasibility Study Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO or ISO. Any waiver of this Interconnection Feasibility Study Agreement shall, if requested, be provided in writing.

Any waivers at any time by any Party of its rights with respect to any default under this Interconnection Feasibility Study Agreement, or with respect to any other matter arising in connection with this Interconnection Feasibility Study Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Interconnection Feasibility Study Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Interconnection Feasibility Study Agreement shall not constitute or be deemed a waiver of such right.

13.9 Headings. The descriptive headings of the various Articles and Sections of this Interconnection Feasibility Study Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Interconnection Feasibility Study Agreement.

13.10 Multiple Counterparts. This Interconnection Feasibility Study Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

13.11 Amendment. The Parties may by mutual agreement amend this Interconnection Feasibility Study Agreement by a written instrument duly executed by both of the Parties.

13.12 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Interconnection Feasibility Study Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this Interconnection Feasibility Study Agreement upon satisfaction of all applicable laws and regulations.

13.13 Reservation of Rights. The ISO shall have the right to make a unilateral filing with FERC to modify this Interconnection Feasibility Study Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Interconnection Feasibility Study Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Interconnection Feasibility Study Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

13.14 No Partnership. This Interconnection Feasibility Study Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

13.15 Assignment. This Interconnection Feasibility Study Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this Interconnection Feasibility Study Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Interconnection Feasibility Study Agreement; and provided further that the Interconnection Customer shall have the right to assign this Interconnection Feasibility Study Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the Large Generating Unit, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). Any

attempted assignment that violates this Article is void and ineffective. Any assignment under this Interconnection Feasibility Study Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

California Independent System Operator Corporation

By: _____

Title: _____

Date: _____

[Insert name of the Interconnection Customer]

By: _____

Title:_____

Date:_____

Attachment A to
Interconnection Feasibility
Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE
INTERCONNECTION FEASIBILITY STUDY

The Interconnection Feasibility Study will be based upon the information set forth in the Interconnection Request and agreed upon in the Scoping Meeting held on_____:

Designation of Point of Interconnection and configuration to be studied.

Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by the Interconnection Customer and other assumptions to be provided by the Interconnection Customer and the ISO]

INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this___day of _____, 20___by and between _____, a _____ organized and existing under the laws of the State of _____, ("Interconnection Customer,") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, ("ISO"). The Interconnection Customer and the ISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated _____; and

WHEREAS, the Interconnection Customer desires to interconnect the Large Generating Facility with the ISO Controlled Grid; and

WHEREAS, the ISO has completed an Interconnection Feasibility Study (the "Feasibility Study") and provided the results of said study to the Interconnection Customer[1]; and

WHEREAS, the Interconnection Customer has requested the ISO to conduct or cause to be performed an Interconnection System Impact Study to assess the impact of interconnecting the Large Generating Facility;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the ISO's FERC-approved Standard Large Generation Interconnection Procedures ("LGIP") or the Master Definitions Supplement, Appendix A to the ISO Tariff, as applicable.

2.0 The Interconnection Customer elects and the ISO shall conduct or cause to be performed an Interconnection System Impact Study consistent with the LGIP in accordance with the ISO Tariff.

3.0 The scope of the Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study and the technical information provided by the Interconnection Customer in the Interconnection Request, subject to any modifications in accordance with Section 4.4 of the LGIP. The ISO reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection System Impact Study. If the

[1] This recital to be omitted if the Interconnection Customer has elected to forego the Interconnection Feasibility Study.

Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the Interconnection System Impact Study may be extended.

5.0 The Interconnection System Impact Study report shall provide the following information:

- identification of any circuit breaker short circuit capability limits exceeded on the Participating TO's electric system or the ISO Controlled Grid as a result of the interconnection;

- identification of any thermal overload or voltage limit violations on the Participating TO's electric system or the ISO Controlled Grid resulting from the interconnection;

- identification of any instability or inadequately damped response to system disturbances on the Participating TO's electric system or the ISO Controlled Grid resulting from the interconnection;

- a description and non-binding, good faith estimate of cost and cost responsibility for and time for construction of facilities on the Participating TO's electric system required to interconnect the Large Generating Facility to the ISO Controlled Grid and to address the identified short circuit, instability, and power flow issues on the ISO Controlled Grid; and

- a Deliverability Assessment on the ISO Controlled Grid pursuant to Section 3.3 of the LGIP; and

- assessment of the potential magnitude of financial impacts, if any, on Local Furnishing Bonds and a proposed resolution.

6.0 The Interconnection Customer shall provide a deposit of $50,000 for the performance of the Interconnection System Impact Study. The good faith estimate for the time of completion of the Interconnection System Impact Study is _____[insert date].

Following the issuance of the Interconnection System Impact Study, the ISO shall charge and the Interconnection Customer shall pay the actual costs of the Interconnection System Impact Study, inclusive of any re-studies and amendments to the Interconnection System Impact Study, pursuant to Section 9 of this Agreement.

Any difference between the deposit made toward the Interconnection System Impact Study, amendments and re-studies to the Interconnection System Impact Study, and the actual cost of the study shall be paid by or refunded to the Interconnection Customer, as appropriate in accordance with Section 13.3 of the LGIP.

7.0 Pursuant to Section 3.7 of the LGIP, the ISO will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems. The ISO may provide a copy of the Interconnection System Impact Study results to an Affected System Operator and the Western Electricity Coordinating Council. Requests for review and input from Affected System Operators or the Western Electricity Coordinating Council may arrive at any time prior to interconnection, and a revision of the Interconnection System Impact Study or re-study may be required in such event.

8.0 Substantial portions of technical data and assumptions used to perform the Interconnection System Impact Study, such as system conditions, existing and planned generation, and unit modeling, may change after the ISO provides the Interconnection System Impact Study results to the Interconnection Customer. Study results will reflect available data at the time the ISO provides the Interconnection System Impact Study to the Interconnection Customer. The ISO shall not be responsible for any additional costs, including, without limitation, costs of new or additional facilities, system upgrades, or schedule changes, that may be incurred by the Interconnection Customer as a result of changes in such data and assumptions.

9.0 In the event that a re-study or amendment of the Interconnection System Impact Study is required, the ISO shall provide notification of the need for such re-study or amendment, and the Interconnection Customer shall provide direction as to whether to proceed with the re-study or amendment and any associated deposit payment pursuant to Section 7.6 or Section 12.2.4 of the LGIP, as applicable.

10.0 The ISO shall maintain records and accounts of all costs incurred in performing the Interconnection System Impact Study, inclusive of any re-studies or amendments thereto, in sufficient detail to allow verification of all costs incurred, including associated overheads. The Interconnection Customer shall have the right, upon reasonable notice, within a reasonable time at the Participating TO's offices and at its own expense, to audit the ISO's records as necessary and as appropriate in order to verify costs incurred by the ISO. Any audit requested by the Interconnection Customer shall be completed, and written notice of any audit dispute provided to the ISO representative, within one hundred eighty (180) Calendar Days following receipt by the Interconnection Customer of the ISO's notification of the final costs of the Interconnection System Impact Study, inclusive of any re-study or amendment thereto.

11.0 In accordance with Section 3.8 of the LGIP, the Interconnection Customer may withdraw its Interconnection Request at any time by written notice to the ISO. Upon receipt of such notice, this Agreement shall terminate.

12.0 Pursuant to Section 7.2 of the LGIP, this Agreement shall become effective upon the date the fully executed Agreement and deposit specified in Section 6 of this Agreement are received by the ISO. If ISO does not receive the fully executed Agreement and payment pursuant to Section 7.2 of the LGIP, then the Interconnection Request will be deemed withdrawn upon the Interconnection Customer's receipt of written notice by the ISO pursuant to Section 3.8 of the LGIP.

13.0 Miscellaneous.

13.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Interconnection System Impact Study Agreement, shall be resolved in accordance with Section 13.5 of the LGIP.

13.2 Confidentiality. Confidential Information shall be treated in accordance with Section 13.1 of the LGIP.

13.3 Binding Effect. This Interconnection System Impact Study Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

13.4 Conflicts. In the event of a conflict between the body of this Interconnection System Impact Study Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Interconnection System Impact Study Agreement shall prevail and be deemed the final intent of the Parties.

13.5 Rules of Interpretation. This Interconnection System Impact Study Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Interconnection System Impact Study Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Interconnection System Impact Study Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article or Section of this Interconnection System Impact Study Agreement or such Appendix to this Interconnection System Impact Study Agreement, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Interconnection System Impact Study Agreement as a whole and not to any particular Article, Section, or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

13.6 Entire Agreement. This Interconnection System Impact Study Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Interconnection System Impact Study Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this Interconnection System Impact Study Agreement.

13.7 No Third Party Beneficiaries. This Interconnection System Impact Study Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

13.8 Waiver. The failure of a Party to this Interconnection System Impact Study Agreement to insist, on any occasion, upon strict performance of any provision of this Interconnection System Impact Study Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Interconnection System Impact Study Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Interconnection System Impact Study Agreement. Termination or default of this

Interconnection System Impact Study Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO or ISO. Any waiver of this Interconnection System Impact Study Agreement shall, if requested, be provided in writing.

Any waivers at any time by any Party of its rights with respect to any default under this Interconnection System Impact Study Agreement, or with respect to any other matter arising in connection with this Interconnection System Impact Study Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Interconnection System Impact Study Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Interconnection System Impact Study Agreement shall not constitute or be deemed a waiver of such right.

13.9 Headings. The descriptive headings of the various Articles and Sections of this Interconnection System Impact Study Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Interconnection System Impact Study Agreement.

13.10 Multiple Counterparts. This Interconnection System Impact Study Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

13.11 Amendment. The Parties may by mutual agreement amend this Interconnection System Impact Study Agreement by a written instrument duly executed by both of the Parties.

13.12 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Interconnection System Impact Study Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this Interconnection System Impact Study Agreement upon satisfaction of all applicable laws and regulations.

13.13 Reservation of Rights. The ISO shall have the right to make a unilateral filing with FERC to modify this Interconnection System Impact Study Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Interconnection System Impact Study Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Interconnection System Impact Study Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

13.14 No Partnership. This Interconnection System Impact Study Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

13.15 Assignment. This Interconnection System Impact Study Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this Interconnection System Impact Study Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Interconnection System Impact Study Agreement; and provided further that the Interconnection Customer shall have the right to assign this Interconnection System Impact Study Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the Large Generating Unit, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Interconnection System Impact Study Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

California Independent System Operator Corporation

By: _____

Title: _____

Date: _____

[Insert name of the Interconnection Customer]

By: _____

Title: _____

Date: _____

Attachment A

Interconnection System Impact Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE INTERCONNECTION SYSTEM IMPACT STUDY

The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study, subject to any modifications in accordance with Section 4.4 of the LGIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied.

Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by the Interconnection Customer and other assumptions to be provided by the Interconnection Customer and the ISO]

INTERCONNECTION FACILITIES STUDY AGREEMENT

THIS AGREEMENT is made and entered into this___day of _____, 20___by and between _____, a _____ organized and existing under the laws of the State of _____, ("Interconnection Customer,") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, ("ISO"). The Interconnection Customer and the ISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated _____; and

WHEREAS, the Interconnection Customer desires to interconnect the Large Generating Facility with the ISO Controlled Grid;

WHEREAS, the ISO has completed an Interconnection System Impact Study (the "System Impact Study") and provided the results of said study to the Interconnection Customer; and

WHEREAS, the Interconnection Customer has requested the ISO to conduct or cause to be performed an Interconnection Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed on the Participating TO's electric system to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Large Generating Facility to the ISO Controlled Grid.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the ISO's FERC-approved Standard Large Generation Interconnection Procedures ("LGIP") or the Master Definitions Supplement, Appendix A to the ISO Tariff, as applicable.

2.0 The Interconnection Customer elects and the ISO shall conduct or cause to be performed an Interconnection Facilities Study consistent with the LGIP in accordance with the ISO Tariff.

3.0 The scope of the Interconnection Facilities Study shall be subject to the assumptions set forth in Attachment A and the data provided in Attachment B to this Agreement.

4.0 The Interconnection Facilities Study report (i) shall provide a description, estimated cost, including, if applicable, the cost of remedial measures that address the financial impacts, if any, on Local Furnishing Bonds, of (consistent with Attachment A), and schedule for required facilities or for effecting remedial measures that address the financial impacts, if any, on Local Furnishing Bonds within each Participating TO's electric system to interconnect the Large Generating Facility to the ISO Controlled Grid and (ii) shall address the short circuit, instability, and power flow issues identified in the Interconnection System Impact Study.

5.0 The Interconnection Customer shall provide a deposit of the greater of $100,000 or the Interconnection Customer's portion of the estimated monthly cost for the performance of the Interconnection Facilities Study. The time for completion of the Interconnection Facilities Study is specified in Attachment A.

For studies where the estimated cost exceed $100,000, the ISO may invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study for the remaining balance of the estimated Interconnection Facilities Study cost. The Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. The ISO shall continue to hold the amounts on deposit until settlement of the final invoice.

Following the issuance of the Interconnection Facilities Study, the ISO shall charge and the Interconnection Customer shall pay the actual costs of the Interconnection Facilities Study, inclusive of any re-studies and amendments to the Interconnection Facilities Study, pursuant to Section 9 of this Agreement.

Any difference between the deposit made toward the Interconnection Facilities Study and the actual cost of the study, inclusive of any re-studies and amendments thereto, shall be paid by or refunded to the Interconnection Customer, as appropriate in accordance with Section 13.3 of the LGIP.

6.0 The Interconnection Facilities Study will be based upon the results of the Interconnection System Impact Study and the technical information provided by the Interconnection Customer in the Interconnection Request, subject to any modifications in accordance with Section 4.4 of the LGIP. The ISO reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Facilities Study.

If the Interconnection Customer modifies its Interconnection Request or the technical information provided therein is modified, the time to complete the Interconnection Facilities Study may be extended.

7.0 Pursuant to Section 3.7 of the LGIP, the ISO will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems. The ISO may provide a copy of the Interconnection Facilities Study results to an Affected System Operator and the Western Electricity Coordinating Council. Requests for review and input from Affected System Operators or the Western Electricity Coordinating Council may arrive at any time prior to interconnection, and a revision of the Interconnection Facilities Study or re-study may be required in such event.

8.0 Substantial portions of technical data and assumptions used to perform the Interconnection Facilities Study, such as system conditions, existing and planned generation, and unit modeling, may change after the ISO provides the Interconnection Facilities Study results to the Interconnection Customer. Study results will reflect available data at the time the ISO provides the Interconnection Facilities Study to the Interconnection Customer. The ISO shall not be responsible for any additional costs, including, without limitation, costs of new or additional facilities, system upgrades, or schedule changes, that may be incurred by the Interconnection Customer as a result of changes in such data and assumptions.

9.0 In the event that a re-study or amendment of the Interconnection Facilities Study is required, the ISO shall provide notification of the need for such re-study or amendment, and the Interconnection

Customer shall provide direction as to whether to proceed with the re-study or amendment and any associated deposit payment pursuant to Section 8.5 or Section 12.2.4 of the LGIP, as applicable.

10.0 The ISO shall maintain records and accounts of all costs incurred in performing the Interconnection Facilities Study, inclusive of any re-studies or amendments thereto, in sufficient detail to allow verification of all costs incurred, including associated overhead. The Interconnection Customer shall have the right, upon reasonable notice, within a reasonable time at the ISO offices and at its own expense, to audit the ISO's records as necessary and as appropriate in order to verify costs incurred by the ISO. Any audit requested by the Interconnection Customer shall be completed, and written notice of any audit dispute provided to the ISO within one hundred eighty (180) Calendar Days following receipt by the Interconnection Customer of the ISO's notification of the final costs of the Interconnection Facilities Study, inclusive of any re-study or amendment thereto.

11.0 In accordance with Section 3.8 of the LGIP, the Interconnection Customer may withdraw its Interconnection Request at any time by written notice to the ISO. Upon receipt of such notice, this Agreement shall terminate.

12.0 Pursuant to Section 8.1 of the LGIP, this Agreement shall become effective upon the date the fully executed Agreement and deposit specified in Section 6 of this Agreement are received by the ISO. If the ISO does not receive the fully executed Agreement and payment pursuant to Section 8.1 of the LGIP, then the Interconnection Request will be deemed withdrawn upon the Interconnection Customer's receipt of written notice by the ISO pursuant to Section 3.8 of the LGIP.

13.0 Miscellaneous.

13.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Interconnection Facilities Study Agreement, shall be resolved in accordance with Section 13.5 of the LGIP.

13.2 Confidentiality. Confidential Information shall be treated in accordance with Section 13.1 of the LGIP.

13.3 Binding Effect. This Interconnection Facilities Study Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

13.4 Conflicts. In the event of a conflict between the body of this Interconnection Facilities Study Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Interconnection Facilities Study Agreement shall prevail and be deemed the final intent of the Parties.

13.5 Rules of Interpretation. This Interconnection Facilities Study Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Interconnection Facilities Study Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Interconnection Facilities Study Agreement), document, instrument or tariff means such agreement, document,

instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article or Section of this Interconnection Facilities Study Agreement or such Appendix to this Interconnection Facilities Study Agreement, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Interconnection Facilities Study Agreement as a whole and not to any particular Article, Section, or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

13.6 Entire Agreement. This Interconnection Facilities Study Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Interconnection Facilities Study Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this Interconnection Facilities Study Agreement.

13.7 No Third Party Beneficiaries. This Interconnection Facilities Study Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

13.8 Waiver. The failure of a Party to this Interconnection Facilities Study Agreement to insist, on any occasion, upon strict performance of any provision of this Interconnection Facilities Study Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Interconnection Facilities Study Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Interconnection Facilities Study Agreement. Termination or default of this Interconnection Facilities Study Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO or ISO. Any waiver of this Interconnection Facilities Study Agreement shall, if requested, be provided in writing.

Any waivers at any time by any Party of its rights with respect to any default under this Interconnection Facilities Study Agreement, or with respect to any other matter arising in connection with this Interconnection Facilities Study Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Interconnection Facilities Study Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Interconnection Facilities Study Agreement shall not constitute or be deemed a waiver of such right.

13.9 Headings. The descriptive headings of the various Articles and Sections of this Interconnection Facilities Study Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Interconnection Facilities Study Agreement.

13.10 Multiple Counterparts. This Interconnection Facilities Study Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

13.11 Amendment. The Parties may by mutual agreement amend this Interconnection Facilities Study Agreement by a written instrument duly executed by both of the Parties.

13.12 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Interconnection Facilities Study Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this Interconnection Facilities Study Agreement upon satisfaction of all applicable laws and regulations.

13.13 Reservation of Rights. The ISO shall have the right to make a unilateral filing with FERC to modify this Interconnection Facilities Study Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Interconnection Facilities Study Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Interconnection Facilities Study Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

13.14 No Partnership. This Interconnection Facilities Study Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

13.15 Assignment. This Interconnection Facilities Study Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this Interconnection Facilities Study Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Interconnection Facilities Study Agreement; and provided further that the Interconnection Customer shall have the right to assign this Interconnection Facilities Study Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the Large Generating Unit, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). Any attempted assignment that

violates this Article is void and ineffective. Any assignment under this Interconnection Facilities Study Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

California Independent System Operator Corporation

By: _____

Title: _____

Date: _____

[Insert name of the Interconnection Customer]

By: _____

Title: _____

Date: _____

Attachment A

**Interconnection Facilities
Study Agreement**

INTERCONNECTION CUSTOMER SCHEDULE ELECTION FOR CONDUCTING THE INTERCONNECTION FACILITIES STUDY

The ISO shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to the Interconnection Customer. Prior to issuing draft study results to the Interconnection Customer, the Participating TO and ISO shall share results for review and incorporate comments within the following number of days after of receipt of an executed copy of this Interconnection Facilities Study Agreement:

- one hundred twenty (120) Calendar Days with no more than a +/- 20 percent cost estimate contained in the report, or

- two hundred ten (210) Calendar Days with no more than a +/- 10 percent cost estimate contained in the report.

Attachment B

Interconnection Facilities Study Agreement

DATA FORM TO BE PROVIDED BY THE INTERCONNECTION CUSTOMER WITH THE INTERCONNECTION FACILITIES STUDY AGREEMENT

Provide two copies of this completed form and other required plans and diagrams in accordance with Section 8.1 of the LGIP.

Provide location plan and one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

One set of metering is required for each generation connection to the new bus or existing ISO Controlled Grid station. Number of generation connections: _____

On the one line indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one line indicate the location of auxiliary power. (Minimum load on CT/PT)

Will an alternate source of auxiliary power be available during CT/PT maintenance? ____Yes _____No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? _____Yes _____No
(Please indicate on one line).

What type of control system or PLC will be located at the Interconnection Customer's Large Generating Facility?

_____
_____

What protocol does the control system or PLC use?

_____
_____

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

Physical dimensions of the proposed interconnection station:

Bus length from generation to interconnection station:

Line length from interconnection station to the Participating TO's transmission line.

Tower number observed in the field. (Painted on tower leg)*

Number of third party easements required for transmission lines*:

* To be completed in coordination with the Participating TO or ISO.

Is the Large Generating Facility in the Participating TO's service area?

_____Yes _____No

Local service provider for auziliary and other power:

Please provide proposed schedule dates:

Begin Construction	Date:
Generator step-up transformer receives back feed power	Date:
Generation Testing	Date:
Commercial Operation	Date:

Level of Deliverability: Choose one of the following:

_____ Deliverability with no Network Upgrades

_____100% Deliverability

OPTIONAL INTERCONNECTION STUDY AGREEMENT

THIS AGREEMENT is made and entered into this___day of _____, 20___by and between _____, a _____ organized and existing under the laws of the State of _____, ("Interconnection Customer,") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, ("ISO"). The Interconnection Customer and the ISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated _____;

WHEREAS, the Interconnection Customer is proposing to establish an interconnection with the ISO Controlled Grid; and

WHEREAS, the Interconnection Customer has submitted to the ISO an Interconnection Request; and

WHEREAS, on or after the date when the Interconnection Customer receives the Interconnection System Impact Study results, the Interconnection Customer has further requested that the ISO conduct or cause to be performed an Optional Interconnection Study;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the ISO's FERC-approved Standard Large Generation Interconnection Procedures ("LGIP") or the Master Definitions Supplement, Appendix A to the ISO Tariff, as applicable.

2.0 The Interconnection Customer elects and the ISO shall conduct or cause to be performed an Optional Interconnection Study consistent with the LGIP in accordance with the ISO Tariff.

3.0 The scope of the Optional Interconnection Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Optional Interconnection Study shall be performed solely for informational purposes.

5.0 The Optional Interconnection Study report shall provide a sensitivity analysis based on the assumptions specified by the Interconnection Customer in Attachment A to this Agreement. The Optional Interconnection Study will identify the Participating TO's Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, including, if applicable, the cost of remedial measures that address the financial impacts, if any, on Local Furnishing Bonds, that may be required to provide transmission service or interconnection service based upon the assumptions specified by the Interconnection Customer in Attachment A.

6.0 The Interconnection Customer shall provide a deposit of $10,000 for the performance of the Optional Interconnection Study. The ISO's good faith estimate for the time of completion of the Optional Interconnection Study is _____ [insert date].

Following the issuance of the Optional Interconnection Study, the ISO shall charge and the Interconnection Customer shall pay the actual costs of the Optional Interconnection Study.

Any difference between the initial payment and the actual cost of the study shall be paid by or refunded to the Interconnection Customer, as appropriate.

7.0 Substantial portions of technical data and assumptions used to perform the Optional Interconnection Study, such as system conditions, existing and planned generation, and unit modeling, may change after the ISO provides the Optional Interconnection Study results to the Interconnection Customer. Study results will reflect available data at the time the ISO provides the Optional Interconnection Study to the Interconnection Customer. The ISO shall not be responsible for any additional costs, including without limitation, costs of new or additional facilities, system upgrades, or schedule changes, that may be incurred by the Interconnection Customer as a result of changes in such data and assumptions.

8.0 The ISO shall maintain records and accounts of all costs incurred in performing the Optional Interconnection Study in sufficient detail to allow verification of all costs incurred, including associated overheads. The Interconnection Customer shall have the right, upon reasonable notice, within a reasonable time at the ISO offices and at its own expense, to audit the ISO's records as necessary and as appropriate in order to verify costs incurred by the ISO. Any audit requested by the Interconnection Customer shall be completed, and written notice of any audit dispute provided to the ISO representative, within one hundred eighty (180) Calendar Days following receipt by the Interconnection Customer of the ISO's notification of the final costs of the Optional Interconnection Study.

9.0 Pursuant to Section 10.1 of the LGIP, this Agreement shall become effective upon the date the fully executed Agreement and deposit specified in Section 6 of this Agreement are received by the ISO. If the ISO does not receive the fully executed Agreement and payment pursuant to Section 10.1 of the LGIP, then the offer reflected in this Agreement will expire and this Agreement will be of no effect.

10.0 Miscellaneous.

10.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Optional Interconnection Study Agreement, shall be resolved in accordance with Section 13.5 of the LGIP

10.2 Confidentiality. Confidential Information shall be treated in accordance with Section 13.1 of the LGIP.

10.3 Binding Effect. This Optional Interconnection Study Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

10.4 Conflicts. In the event of a conflict between the body of this Optional Interconnection Study Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Optional Interconnection Study Agreement shall prevail and be deemed the final intent of the Parties.

10.5 Rules of Interpretation. This Optional Interconnection Study Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Optional Interconnection Study Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Optional Interconnection Study Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article or Section of this Optional Interconnection Study Agreement or such Appendix to this Optional Interconnection Study Agreement, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Optional Interconnection Study Agreement as a whole and not to any particular Article, Section, or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

10.6 Entire Agreement. This Optional Interconnection Study Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Optional Interconnection Study Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this Optional Interconnection Study Agreement.

10.7 No Third Party Beneficiaries. This Optional Interconnection Study Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

10.8 Waiver. The failure of a Party to this Optional Interconnection Study Agreement to insist, on any occasion, upon strict performance of any provision of this Optional Interconnection Study Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Optional Interconnection Study Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Optional Interconnection Study Agreement. Termination or default of this Optional Interconnection Study Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the other Party. Any waiver of this Optional Interconnection Study Agreement shall, if requested, be provided in writing.

Any waivers at any time by any Party of its rights with respect to any default under this Optional Interconnection Study Agreement, or with respect to any other matter arising in connection with this Optional Interconnection Study Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Optional Interconnection Study Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Optional Interconnection Study Agreement shall not constitute or be deemed a waiver of such right.

10.9 Headings. The descriptive headings of the various Articles and Sections of this Optional Interconnection Study Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Optional Interconnection Study Agreement.

10.10 Multiple Counterparts. This Optional Interconnection Study Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

10.11 Amendment. The Parties may by mutual agreement amend this Optional Interconnection Study Agreement by a written instrument duly executed by both of the Parties.

10.12 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Optional Interconnection Study Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this Optional Interconnection Study Agreement upon satisfaction of all applicable laws and regulations.

10.13 Reservation of Rights. The ISO shall have the right to make a unilateral filing with FERC to modify this Optional Interconnection Study Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Optional Interconnection Study Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Optional Interconnection Study Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

10.14 No Partnership. This Optional Interconnection Study Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

10.15 Assignment. This Optional Interconnection Study Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this Optional Interconnection Study Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Optional Interconnection Study Agreement; and provided further that the Interconnection

Customer shall have the right to assign this Optional Interconnection Study Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the Large Generating Unit, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Optional Interconnection Study Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

California Independent System Operator Corporation

By: _____

Title: _____

Date: _____

[Insert name of the Interconnection Customer]

By: _____

Title: _____

Date: _____

Attachment A
Optional Interconnection
Study Agreement

ASSUMPTIONS USED IN CONDUCTING
THE OPTIONAL INTERCONNECTION STUDY

[To be completed by the Interconnection Customer consistent with Section 10 of the LGIP.]

AGREEMENT FOR THE ALLOCATION OF RESPONSIBILITIES WITH REGARD TO LARGE GENERATOR INTERCONNECTION PROCEDURES AND INTERCONNECTION STUDY AGREEMENTS

This Agreement for the Allocation of Responsibilities With Regard to Large Generator Interconnection Procedures and Interconnection Study Agreements ("Agreement"), dated November 1, 2005, is entered into between the California Independent System Operator Corporation ("ISO") and **[NAME OF PTO]**_____("PTO"). The ISO and PTO are jointly referred to as the "Parties" and individually, as a "Party."

WHEREAS, this Agreement will ensure an independent assessment of new Large Generating Facility impacts on the ISO Controlled Grid and take advantage of the respective expertise of the Parties to facilitate efficient and cost effective Interconnection Study procedures in a manner consistent with the Federal Energy Regulatory Commission's ("FERC") July 1, 2005 Order (112 FERC ¶ 61,009), FERC's August 26, 2005 Order (112 FERC ¶ 61,231), and prior FERC Orders recognizing that Order No. 2003 did not allocate responsibilities between transmission owners and transmission providers for the provision of Interconnection Service and suggesting those parties enter into an agreement to allocate those responsibilities. Southwest Power Pool, Inc., 106 FERC ¶ 61,254 (2004).

NOW THEREFORE, in view of the respective responsibilities assigned to the Parties and the foregoing FERC orders, the ISO and PTO agree to the following allocation of responsibilities for a centralized Interconnection Study process under the direction and oversight of the ISO:

1. DEFINITIONS.

Unless otherwise defined herein, all capitalized terms shall have the meaning set forth in the ISO Tariff.

2. TERM OF AGREEMENT.

This Agreement shall become effective upon the date the provisions of the ISO Tariff implementing the centralized Interconnection Study process required by the July 1 Order and the August 26 Order are accepted and made effective by FERC, and shall remain in effect until (1) terminated by all Parties in writing, or (2) with respect to the PTO, upon the termination of that entity's status as a PTO pursuant to the Transmission Control Agreement, as amended from time to time.

3. PROVISIONS FOR ALLOCATION OF RESPONSIBILITIES BETWEEN ISO AND PTO.

3.1 Interconnection Service: The Parties acknowledge that, as the transmission provider, the ISO is responsible for reliably operating the transmission grid. The Parties also recognize that while the ISO is a transmission provider under the ISO Tariff, the ISO does not own any transmission facilities, and the PTO owns, constructs, and maintains the facilities to which Large Generating Facilities are to be interconnected, and that the PTO may construct or modify facilities to allow the interconnection. While the Parties recognize that the ISO will be responsible for conducting or causing to be performed Interconnection Studies and similar studies, the PTO will participate in these studies and conduct certain portions of studies, under the direction and oversight of, and approval by, the ISO, as provided in this Agreement. The ISO shall not enter into any Interconnection Study agreement with an Interconnection Customer that is contrary to these rights.

3.2 [INTENTIONALLY LEFT BLANK]

3.3 Transmission Owners' Right to Participation in Studies, Committees and Meetings:

3.3.1 In the event that an Interconnection Customer proposes to interconnect a Large Generating Facility with the PTO's facilities, or the PTO is an owner of an affected system, the PTO shall have the right to participate in any Interconnection Feasibility Study, Interconnection System Impact Study, Interconnection Facilities Study, or any other study conducted in connection with such request for Interconnection Service. "Participate" in this Section 3.3.1 means physically perform any study or portion thereof in connection with an Interconnection Request, under the direction and oversight of, and approval by, the ISO pursuant to Section 3.4 of this Agreement; provide or receive input, data or other information regarding any study or portion thereof consistent with Section 3.4 of this Agreement; and, when any study or portion thereof in connection with an Interconnection Request is physically performed by an entity other than the PTO, perform activities necessary to adequately review or validate, as appropriate, any results of the study or portions thereof and provide recommendations.

3.3.2 In the event that an Interconnection Customer proposes to interconnect a Large Generating Facility with the PTO's facilities, or the PTO is an owner of an affected system, the PTO shall have the right to participate in all meetings expressly established pursuant to the ISO LGIP. As appropriate, the PTO may participate in all other material or substantive communications in connection with an Interconnection Request.

3.4 Interconnection Study Responsibility Allocation: In complying with its responsibility for conducting or causing to be performed Interconnection Studies, the ISO will assign responsibility for performance of portions of the Interconnection Studies to the PTO, under the direction and oversight of, and approval by, the ISO, as set forth in Attachment A, except as specifically qualified as follows:

3.4.1 Unless an Interconnection Customer specifically requests that a third party perform an Interconnection Study pursuant to LGIP Section 13.4, for any tasks specifically assigned to the PTO pursuant to Attachment A or otherwise mutually agreed upon by the ISO and the PTO, the ISO reserves the right, on a case-by-case basis, to perform or reassign to a mutually agreed upon and pre-qualified contractor such task only where: (a) the quality and accuracy of prior PTO Interconnection Study work product resulting from assigned tasks has been deemed deficient by the ISO, the ISO has notified the PTO pursuant to notice provision Section 4.16 in writing of the deficiency, and the deficiency has not been cured pursuant to Section 3.4.2; (b) the timeliness of PTO Interconnection Study work product has been deemed deficient, and either (i) the ISO has not been notified of the reasons and actions taken to address the timeliness of the work, or (ii) if notified, the stated reasons and actions taken are insufficient or unjustifiable and the PTO has not cured the deficiency pursuant to Section 3.4.2; (c) the PTO has failed, in a mutually agreed upon timeframe, to provide the ISO with information or data related to an Interconnection Request despite a written request by the ISO, pursuant to Section 3.5 hereof, to do so, and such data is the responsibility of the PTO to provide to the ISO, subject to Section 4.3 of this Agreement; (d) the PTO advises the ISO in writing that it does not have the resources to adequately or timely perform the task according to the applicable timelines set forth in Attachment A; or (e) the estimated cost of the PTO

performing the task has been determined in writing by the ISO to significantly exceed the cost of the ISO or mutually agreed upon contractor performing the task, inclusive of the costs that will be incurred by the PTO in exercising its review rights of the results of any such tasks performed by such third party(ies). If the ISO deviates from the assignments set forth in Attachment A based on the foregoing factors, the ISO will provide the PTO with a written explanation for the deviation and any associated reassignments of work. The PTO may contest the deviation pursuant to the Dispute Resolution procedures set forth in Section 4.1 of this Agreement.

Task(s) may only be reassigned in accordance with this Section 3.4.1 where the PTO has been deemed to be deficient in relation to that (those) particular task(s).

3.4.2 Cure for re-assigned Interconnection Study work

The ISO shall not reassign task(s) without the opportunity to cure, as specified in Section 3.4.1. The following actions will serve to cure the deficiencies and result in restoring the assignment(s) as provided in Attachment A:

a) The ISO and PTO shall negotiate in good faith and agree to a corrective action plan proposed by the PTO, including a reasonably adequate cure period, and the corrective action plan is satisfactorily implemented.

b) The ISO determines the deficiency is cured without an action plan.

3.4.3 Assessment of prior PTO Interconnection Study work shall only be based on work conducted under the process that becomes effective concurrent with the effective date of this Agreement. Further, assessment of prior PTO Interconnection Study work shall be based on work conducted no earlier than the eighteen (18) month period prior to the date of the ISO notice of deviation from assignments set forth in Attachment A to this Agreement.

3.5 Information Exchange: The PTO shall provide the ISO, subject to confidentiality requirements in Section 4.3, with any documentation or data requested by the ISO reasonably necessary to permit the ISO to perform, review, validate and approve any Interconnection Study, or portion thereof, performed by the PTO. The ISO shall provide the PTO with any documentation or data requested by the PTO, subject to confidentiality requirements in Section 4.3, reasonably necessary to perform, review, and validate any Interconnection Study, or portion thereof.

3.6 Consistency with Provisions for Centralized Interconnection Study Process: The ISO and PTO have determined that the processes and allocation of responsibilities in Section 3.4 of this Agreement ensure that impacts to the ISO Controlled Grid are independently assessed and that the assignment of responsibilities minimizes handoffs, takes advantage of non-transferable skills, and promotes the efficiency and cost-effectiveness of the centralized Interconnection Study processes, consistent with LGIP Section 3.2.

3.7 Re-Studies: If any re-studies are required, the ISO will confer with the PTO as to the need for a re-study. The ISO will make the final determination regarding the need for a re-study, subject to dispute resolution procedures.

3.8 Use of Contractors: Nothing in this Agreement shall prevent either the ISO or the PTO from using qualified, mutually agreed upon third party contractors to meet that Party's rights or obligations under this Agreement or the LGIP. To promote the efficiency of the process, the ISO and PTO will collaborate to identify a list of the mutually agreed to qualified contractors available to the Parties.

3.9 Performance Standards: Each Party shall perform all of its obligations under the LGIP, this Agreement, and any FERC approved Interconnection Study procedures that may be adopted by the ISO to implement the LGIP or this Agreement in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice.

3.10 Recovery of Costs: In accordance with Section 13.3 of the LGIP, the PTOs shall recover all actual costs from the ISO incurred in performing Interconnection Studies or portions thereof assigned to it by the ISO, including all costs incurred in exercising its right to review, and make recommendations on, Interconnection Studies or portions thereof performed by the ISO and/or contractors under Section 3.8 of this Agreement.

4 GENERAL TERMS AND CONDITIONS.

4.1 Dispute Resolution: In the event any dispute regarding the terms, conditions, and performance of this Agreement is not settled informally, the Parties shall follow the ISO ADR Procedures set forth in Section 13 of the ISO Tariff.

4.2 Liability: No Party to this Agreement shall be liable to any other Party for any direct, indirect, special, incidental or consequential losses, damages, claims, liabilities, costs or expenses (including attorneys fees and court costs) arising from the performance or non-performance of its obligations under this Agreement regardless of the cause (including intentional action, willful action, gross or ordinary negligence, or force majeure); provided, however, that a Party may seek equitable or other non-monetary relief as may be necessary to enforce this Agreement and that damages for which a Party may be liable to another Party under another agreement will not be considered damages under this Agreement.

4.3 Confidentiality: Confidential Information shall be treated in accordance with Section 13.1 of the LGIP.

4.4 Binding Effect: This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

4.5 Conflicts: In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

4.6 Rules of Interpretation: This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Section, or other provision hereof or thereof); (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article or Section of this Agreement or such Appendix to this Agreement, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Agreement as a whole and not to any particular Article; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

4.7 Entire Agreement: This Agreement, including all Attachments hereto, constitutes the entire agreement among the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, among the Parties with respect to the subject matter of this Agreement. Thereare no other agreements, representations, warranties, or covenants, which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this Agreement.

4.8 No Third Party Beneficiaries: This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

4.9 Waiver: The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party. Any waiver at any time by a Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Any waiver of this Agreement shall, if requested, be provided in writing. Any waivers at any time by any Party of its rights with respect to any default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Agreement shall not constitute or be deemed a waiver of such right.

4.10 Headings: The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

4.11 Multiple Counterparts: This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

4.12 Modification by the Parties: The Parties may amend this Agreement and any Appendices to this Agreement only (1) by mutual agreement of the Parties by a written instrument duly executed by the Parties, subject to FERC approval or (2) upon the issuance of a FERC order, pursuant to Section 206 of the Federal Power Act. It is the Parties' intent that FERC's right to change any provision of this Agreement shall be limited to the maximum extent permissible by law and that any such change, if permissible, shall be in accordance with the Mobile-Sierra public interest standard applicable to fixed rate agreements. *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956). Such amendment shall become effective and a part of this Agreement upon satisfaction of all applicable laws and regulations. Notwithstanding the foregoing, Attachment B (Notices) may be modified as set forth in Section 4.15, and the ISO and the PTO may from time to time mutually agree to deviate from Attachment A in accordance with the provisions of this Agreement, however, such deviation shall be subject to Section 4.9 and not considered a course of dealing.

4.13 No Partnership: This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

4.14 Assignment: This Agreement may be assigned by a Party only with the written consent of the other Parties; provided that a Party may assign this Agreement without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater creditrating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement. Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

4.15 Notices: Any notice, demand, or request provided in this Agreement, or served, given, or made in connection with it, will be in writing and deemed properly served, given, or made if delivered in person, transmitted by facsimile, or sent by United States mail, postage prepaid, to the persons specified in Attachment B hereto unless otherwise provided in this Agreement. Any Party may at any time, by notice to all other Parties, change the designation or address of the person specified in Attachment B as the person who receives notices pursuant to this Agreement.

IN WITNESS WHEREOF, the Parties have executed this Agreement in multiple originals, each of which shall constitute and be an original effective agreement among the Parties.

California Independent System Operator Corporation

By: _____

Title: _____

Date: _____

[NAME OF PTO]

By: _____

Title: _____

Date: _____

ATTACHMENT A

INTERCONNECTION STUDY RESPONSIBILITY ALLOCATION

Description of Large Generator Interconnection Process: Roles and Responsibilities of ISO and PTOs.

Purpose: This Attachment A to the "AGREEMENT FOR THE ALLOCATION OF RESPONSIBILITIES WITH REGARD TO LARGE GENERATOR INTERCONNECTION PROCEDURES AND INTERCONNECTION STUDY AGREEMENTS" serves as further clarification of the roles and responsibilities of the parties to this Agreement. The ISO will assign responsibility for performance of portions of the Interconnection Studies to the relevant PTOs, under the direction and oversight of, and approval by, the ISO, as set forth in this Attachment A. This document serves as a general overview of only the roles and responsibilities as between the ISO and PTOs. This Agreement does not include the process steps, involvement or obligations of the Interconnection Customer (IC). This Agreement is not inclusive of all procedures necessary to comply with all provisions of the LGIA, LGIP and Interconnection Study agreements.

Interconnection Request (IR) Process

1. ISO forwards the IR to the PTO within 1 Business Day (BD) of receipt of IR from Interconnection Customer (IC)
2. PTO(s) provides any feed back regarding IR to ISO within 3 BD
3. PTO(s) provides draft study plan at Scoping Meeting.
4. ISO distributes draft Scoping Meeting Minutes for review within 3 BD of Scoping Meeting.
5. PTO(s) provide any comments to the Scoping Meeting Minutes within 2 BD of receipt of draft Scoping Meeting Minutes.
6. ISO issues the final Scoping Meeting Minutes within 3 BD of receipt of comments.

Interconnection Feasibility Study Process:

1. ISO forwards IC Point of Interconnection and any Appendix 1, Attachment A data to the PTO(s) within 1 BD of ISO receipt.
2. PTO(s) develop updated draft study plan based on technical data collected by ISO from IC within 7 BD.
3. ISO and PTO(s) coordinate to finalize study plan within 2 BD. ISO approves the study plan.
4. ISO tenders a signed IFSA to IC, with final study plan included in Attachment A, within 5 BD (for a total of 15 BD from ISO receipt of Point of Interconnection from IC in accordance with LGIP Section 6.1).
5. After ISO receives executed study agreement, ISO forwards any additional Appendix 1, Attachment A data to PTO(s) within 1 BD.
6. If during the course of the assigned portions of the study the PTO(s) determines the data is not sufficient to complete the study, PTO(s) informs ISO and ISO notices IC in accordance with LGIP Section 3.8.
7. PTO(s) must participate in study review meeting; date to be agreeable to PTO(s) and within 10 BD of ISO providing study report to IC (LGIP Section 6.3.1).
8. ISO and PTO collaborate on any re-study issues. ISO will direct any necessary re-studies.

Interconnection Feasibility Study Timeline

Load Flow	**Typical Calendar Days**	**Typical Cumulative Days**
ISO directs PTO(s) to Develop draft Base Cases **(Milestone)**	0	0
PTO(s) develop draft Base Cases and deliver to ISO	7	7
ISO reviews Base Cases and provides direction to PTO(s) At the direction of the ISO, PTO(s) develops contingency lists and provide to ISO.	7	14
PTO incorporates ISO directions into Base Cases; ISO approves Base Cases; ISO reviews and approves contingency lists. If there is disagreement on the contingency list, the ISO and PTO(s) must coordinate to revise the contingency list. ISO approves the contingency list.	7	21
ISO performs Load Flow & prepares summary results of impacted systems (other PTO(s) or Affected Systems) and submits results to impacted systems. Such results may include ISO proposed solutions for mitigation to any violations uncovered in the Load Flow study.	7	28
Impacted PTO(s) review ISO results and recommend mitigation solutions as appropriate.	5	33
Short Circuit Duty (concurrent with Load Flow Activity)		
At the ISO's direction, PTO(s) Develop Base Case, and run short circuit analyses.	10	10
PTO(s) to perform facilities review	18	28
PTO(s) prepare draft study results and submit to the ISO for review, recommendations and direction.	5	33
Facility cost estimates		
At the ISO's direction, PTO(s) to prepare non-binding cost estimates and schedule for the direct assignment facilities and network upgrades identified in the power flow and short circuit duty analyses.	7	40
Finalizing Report		
At the ISO's direction, PTO(s) to prepare draft report for impacts in their service territory.	5	45
ISO compiles all results into a draft report that covers grid impacts.	5	50
PTO(s) reviews ISO integrated report and provides comments to ISO.	4	54
ISO incorporates PTO(s) comments. If PTO(s') comments conflict with ISO conclusions, then ISO and PTO must coordinate to resolve conflicts. Any remaining conflicts must be noted in final report.	6	60
ISO provides final ISO approved report to IC, impacted PTOs, and any applicable Affected Systems. **(Milestone)**	0	0

Interconnection System Impact Study Process

1. Prior to beginning the ISIS process as outlined in this Attachment A, the ISO will notify the PTOs of potential seams issues and discuss the nature of the concerns with the PTOs. Where the ISO determines that there is a reasonable expectation that the new Large Generating Facility to be interconnected in one PTO area may impact system performance in other PTO areas within the ISO Controlled Grid that does not comply with the applicable planning standards, the ISO will conduct or cause to be performed the ISIS Load Flow, Post Transient and Stability analyses, as appropriate, to assess the extent of the impact on the grid and evaluate mitigation solutions. Applicable planning standards include FERC approved ISO Planning Standards, as may be amended from time to time, and the NERC/WECC Planning Standards, as may be amended from time to time. Further, there may be circumstances where information, including available studies, is not sufficient for the ISO to make a reasonable engineering determination whether the new Large Generating Facility to be interconnected in one PTO area could cause system performance in other PTO areas (i.e. within the ISO Controlled Grid) that does not comply with the applicable planning standards and, in such circumstances, the ISO may nonetheless conduct or cause to be performed the ISIS Load Flow, Post Transient and Stability analyses to make such a determination.
2. At the ISO's direction, the PTO develops a draft ISIS study plan and determines if available technical data is sufficient to complete ISIS.
3. PTO submits draft study plan to ISO for review, direction and approval within 7 BD of ISO tendering Interconnection Feasibility Study report to IC.
4. ISO and PTO coordinate to finalize study plan within 3 BD. ISO approves the study plan.
5. ISO tenders a signed ISISA to IC with final study plan included in Attachment A, within 3 BD.
6. Upon receipt of executed study agreement, ISO forwards any additional Attachment A, Appendix 1 data to PTO(s) within 1 BD.
7. If the data provided by IC is insufficient to perform the study, PTO notifies ISO within 2 BD of ISO receipt of the executed study agreement, and the ISO notifies the IC within 2 BD (total of 5 BD per LGIP Section 7.2) to correct any deficiencies within 10 BD or the IR will be deemed withdrawn, triggering LGIP Section 3.8.
8. PTO must participate in study review meeting; date to be agreeable to PTO and within 10 BD of ISO providing study report to IC (LGIP Section 7.5).
9. ISO to confer with PTO as to the need for a Re-study. ISO makes the final determination subject to dispute resolution procedures.

Interconnection System Impact Study Timeline

Standard System Impact Study Load Flow/Post Transient/Stability Process	**Typical Calendar Days**	**Typical Cumulative Days**
At the ISO's direction, PTO(s) develop draft Base Case(s)	0	0
PTO(s) develop(s) draft base case(s) and deliver(s) to ISO	14	14
ISO reviews Base Case(s) and provides direction to PTO At the ISO's direction, PTO develops contingency lists	7	21
PTO incorporates ISO directions into Base Cases ISO approves Base Case(s) ISO reviews and approves contingency lists	7	28
At the ISO's direction, the PTO may perform the ISIS Load Flow, Post Transient and Stability analyses & prepare mitigation solutions, as appropriate and submits draft study results to ISO for review and direction*.	21	49
***Pursuant to the terms of item 1 above: where the ISO performs the ISIS Load Flow, Post Transient and Stability analyses to determine grid impacts and evaluate mitigation solutions, the potentially impacted PTOs may, as part of the review process, perform activities to adequately review or validate Load Flow, Post Transient and Stability Analysis to assess ISO results and recommend alternative solutions. (In the case of this election, "PTOs" should be substituted for "PTO" for remainder of ISIS process.)**		
PTO develops or supplements ISO proposed mitigation plans and/or develops alternative mitigation plans for consideration, as appropriate, and submits to ISO for review and direction	14	63
Short Circuit Duty (concurrent with the LF/PT/S)		
ISO to coordinate with other potentially affected facility owners[2]	n/a	n/a
ISO directs PTO to develop Base Case and run short circuit analysis	21	21
PTO to perform facilities review	35	56
PTO to prepare draft study results and submits to the ISO for review and direction	7	63
Facility cost estimates and schedules		
At the ISO direction, PTO(s) to prepare cost estimates and schedules for the direct assignment facilities and network upgrades identified in the ISIS power flow, short circuit duty, post transient, and stability studies.	20	83
Final Report		
At the ISO's direction, PTO(s) prepares draft report for impacts in their service territory.	7	90

[2] In accordance with the WECC Short Circuit Duty Procedure

ISO compiles all results into a draft report that covers grid impacts, as appropriate. ISO reviews integrated draft report and submits comments, recommendations and direction to the PTO	9	99
PTO incorporates ISO directions, conclusions and recommendations. If ISO conclusions and recommendations conflict with PTO conclusions then ISO and PTO must coordinate to resolve conflicts. Any remaining conflicts must be noted in the final report.	14	113
PTO submits final draft report less the deliverability results to the ISO. The ISO will finalize the report and tender the ISO approved report to the IC after incorporating Deliverability results.		
ISO Deliverability Assessment (concurrent with other studies) As part of the Deliverability Assessment process pursuant to LGIP Section 3.3.3, the ISO may also perform studies pursuant to LGIP Section 3.3.2 to determine potential operating limitations on the generator due to constraints under a variety of system conditions.		
PTO provides GE PSLF compatible change files for all project changes since last Deliverability Assessment, including subject LGIP project.	14	14
ISO incorporates project changes into Deliverability Base Case.	7	21
ISO provides Deliverability Study & prepares results summary.	14	35
ISO provides Initial Deliverability results with no upgrades and upgrades necessary for full Deliverability	14	49
ISO reviews Load Flow, post transient, and stability analysis mitigation options. (The timing of this action should be in sync with completion of Load Flow study results)	11	60
ISO has the opportunity to revise Deliverability Upgrades necessary for full Deliverability, based on optimization with LF results.	7	67
At the ISO's direction, PTO to provide Deliverability related upgrade costs and schedules, as appropriate. (This action should occur when PTO is performing cost analysis for Load Flow and Short Circuit Duty upgrades)	16	83
ISO drafts Deliverability study results.	7	90
PTO reviews/comments on Deliverability results.	12	102
ISO incorporates PTO comments on the Deliverability results, as appropriate. Any remaining conflicts must be noted in final report.	11	113
Final Study Report		
ISO provides final approved report to IC, PTO, and any applicable affected systems.	7	120

Interconnection Facilities Study Process**

****All Interconnection Facilities Studies will be under the direction and oversight of, and approval by, the ISO and may involve more than one PTO.**

1. Within 5 BD of the ISIS Study Review Meeting, the PTO develops draft Interconnection Facilities Study plan and submits to ISO for review and approval.
2. ISO submits executed Interconnection Facilities Study Agreement to IC within 5 BD.
3. Upon receipt of executed Interconnection Facilities Study Agreement from IC, ISO submits to PTO technical data provided by IC within 1 BD.
4. If the data provided by IC is insufficient to perform the study, PTO notifies ISO within 3 BD and the ISO notifies the IC within 2 BD (total of 5 BD per LGIP) that IR is deemed withdrawn and the reason for the withdrawal. IC has 15 BD to cure withdrawal notice (LGIP goes directly to withdrawal pursuant to Section 3.8).
5. PTO conducts Interconnection Facilities Study and submits draft report to ISO.
6. ISO forwards draft report to IC for comments.
7. ISO forwards IC comments or notice of no comments to PTO within 1 BD of receipt.
8. PTO incorporates IC Comments within 5 BDs and submits updated draft to ISO for review and comment.
9. ISO reviews and comments, provides recommendations and direction on PTO draft Interconnection Facilities Study report within 2 BD.
10. PTO reviews/incorporates ISO directions within 5 BD and sends revised report to ISO.
11. ISO issues final report to IC within 2 BD (total of 15 BD). If PTO comments conflict with ISO recommendations and conclusions, ISO and PTO must coordinate to resolve conflicts. Any remaining conflicts must be noted in the final report.
12. ISO, PTO(s), and IC meet within 10 BDs from issuance of draft report.
13. ISO and PTO collaborate on any re-study issues. ISO will direct any necessary re-studies and/or progress to LGIA process.

ATTACHMENT B

CONTACTS FOR NOTICES

[Section 4.15]

California ISO

Manager, Transmission Engineering
151 Blue Ravine Road
Folsom, CA 95630
Phone: 916.351.2104
Fax: 916.351.2264

[NAME OF PTO]

[Address of PTO]

ISO TARIFF APPENDIX V

Standard Large Generator Interconnection Agreement

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT (LGIA)

[INTERCONNECTION CUSTOMER]

[PARTICIPATING TO]

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

TABLE OF CONTENTS

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

[INTERCONNECTION CUSTOMER]

[PARTICIPATING TO]

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT ("LGIA") is made and entered into this ____ day of _____ 20___, by and among _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ ("Interconnection Customer" with a Large Generating Facility), _____, a corporation organized and existing under the laws of the State of California ("**Participating TO**"), and **California Independent System Operator Corporation**, a California nonprofit public benefit corporation organized and existing under the laws of the State of California ("ISO"). Interconnection Customer, Participating TO, and ISO each may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, ISO exercises Operational Control over the ISO Controlled Grid; and

WHEREAS, the Participating TO owns, operates, and maintains the Participating TO's Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Part C to this LGIA; and

WHEREAS, Interconnection Customer, Participating TO, and ISO have agreed to enter into this LGIA for the purpose of interconnecting the Large Generating Facility with the Participating TO's Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this LGIA, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used.

ARTICLE 1. DEFINITIONS

Adverse System Impact shall mean 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 shall mean an electric system other than the ISO Controlled Grid that may be affected by the proposed interconnection, including the Participating TO's electric system that is not part of the ISO Controlled Grid.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the Western Electricity Coordinating Council or its successor.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Participating TO's Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies.

Breach shall mean the failure of a Party to perform or observe any material term or condition of this LGIA.

Breaching Party shall mean a Party that is in Breach of this LGIA.

Business Day shall mean Monday through Friday, excluding federal holidays and the day after Thanksgiving Day.

Calendar Day shall mean any day including Saturday, Sunday or a federal holiday.

Commercial Operation shall mean the status of an Electric Generating Unit at a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of an Electric Generating Unit shall mean the date on which the Electric Generating Unit at the Generating Facility commences Commercial Operation as agreed to by the applicable Participating TO and the Interconnection Customer pursuant to Part E to this LGIA.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, subject to Article 22.1.2.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of this LGIA.

Distribution System shall mean those non-ISO-controlled transmission and distribution facilities owned by the Participating TO.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Participating TO's Distribution System. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which this LGIA becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Electric Generating Unit shall mean an individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the ISO, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the ISO Controlled Grid or the electric systems of others to which the ISO Controlled Grid is directly connected; (3) that, in the case of the Participating TO, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Participating TO's Transmission System, Participating TO's Interconnection Facilities, Distribution System, or the electric systems of others to which the Participating TO's electric system is directly connected; or (4) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by this LGIA to possess black start capability.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a *et seq*.

FERC shall mean the Federal Energy Regulatory Commission or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean the Interconnection Customer's Electric Generating Unit(s) used for the production of electricity identified in the Interconnection Customer's Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in 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.

Governmental Authority shall mean any federal, state, local or other governmental, regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, ISO, Participating TO, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which an Electric Generating Unit is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Participating TO's Interconnection Facilities to obtain back feed power.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Part A of this LGIA, 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 Participating TO's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean 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 Participating TO's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean the study conducted or caused to be performed by the ISO, in coordination with the applicable Participating TO(s), 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 Participating TO's Transmission System.

Interconnection Facilities Study Agreement shall mean the agreement between the Interconnection Customer and the ISO for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean the preliminary evaluation conducted or caused to be performed by the ISO, in coordination with the applicable Participating TO(s), or a third party consultant for the Interconnection Customer of the system impact and cost of interconnecting the Generating Facility to the Participating TO's Transmission System, and, if reasonably practicable, an informational assessment, as needed, of other affected owners' portions of the ISO Controlled Grid.

Interconnection Handbook shall mean 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 Standards. In the event of a conflict between the terms of this LGIA and the terms of the Participating TO's Interconnection Handbook, the terms in this LGIA shall apply.

Interconnection Request shall mean a request, in the form of Part 1 to the Standard Large Generator Interconnection Procedures, in accordance with the ISO Tariff.

Interconnection Service shall mean the service provided by the Participating TO and ISO associated with interconnecting the Interconnection Customer's Generating Facility to the Participating TO's Transmission System and enabling the ISO Controlled Grid to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of this LGIA, the Participating TO's Transmission Owner Tariff, and the ISO Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study conducted or caused to be performed by the ISO, in coordination with the applicable Participating TO(s), or a third party consultant for the Interconnection Customer pursuant to the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean the engineering study conducted or caused to be performed by the ISO, in coordination with the applicable Participating TO(s), or a third party consultant for the Interconnection Customer that evaluates the impact of the proposed interconnection on the safety and reliability of the Participating TO's Transmission System 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.

IRS shall mean the Internal Revenue Service.

ISO Controlled Grid shall mean the system of transmission lines and associated facilities of the parties to the Transmission Control Agreement that have been placed under the ISO's Operational Control.

ISO Tariff shall mean the ISO's tariff, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all damages, losses, and claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties.

Material Modification shall mean 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.

Metering Equipment shall mean all metering equipment installed or to be installed for measuring the output of the Generating Facility pursuant to this LGIA at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

Network Upgrades shall be Participating TO's Delivery Network Upgrades and Participating TO's Reliability Network Upgrades.

Operational Control shall mean the rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct the parties to the Transmission Control Agreement 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.

Participating TO's Delivery Network Upgrades shall mean the additions, modifications, and upgrades to the Participating TO's Transmission System at or beyond the Point of Interconnection, other than Reliability Network Upgrades, identified in the Interconnection Studies, as identified in Part A, to relieve constraints on the ISO Controlled Grid.

Participating TO's Interconnection Facilities shall mean 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 Part A to this LGIA, 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's Reliability Network Upgrades shall mean the additions, modifications, and upgrades to the Participating TO's Transmission System at or beyond the Point of Interconnection, identified in the Interconnection Studies, as identified in Part A, necessary to interconnect the Large Generating Facility safely and reliably to the Participating TO's Transmission System, which would not have been necessary but for the interconnection of the Large Generating Facility, including additions, modifications, and upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of the Large Generating Facility to the Participating TO's Transmission System. Participating TO's Reliability Network Upgrades also include, consistent with Applicable Reliability Council practice, the Participating TO's facilities necessary to mitigate any adverse impact the Large Generating Facility's interconnection may have on a path's Applicable Reliability Council rating.

Participating TO's Transmission System shall mean the facilities owned and operated by the Participating TO and that have been placed under the ISO's Operational Control, which facilities form part of the ISO Controlled Grid.

Party or Parties shall mean the Participating TO, ISO, Interconnection Customer or the applicable combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Part A to this LGIA, where the Interconnection Customer's Interconnection Facilities connect to the Participating TO's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Part A to this LGIA, where the Interconnection Facilities connect to the Participating TO's Transmission System.

Qualifying Facility shall mean a qualifying cogeneration facility or qualifying small power production facility, as defined in the Code of Federal Regulations, Title 18, Part 292 (18 C.F.R. §292).

QF PGA shall mean a Qualifying Facility Participating Generator Agreement specifying the special provisions for the operating relationship between a Qualifying Facility and the ISO, a pro forma version of which is set forth in Appendix B.3 of the ISO Tariff.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under this LGIA, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting among representatives of the Interconnection Customer, the Participating TO(s), other Affected Systems, 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.

Stand Alone Network Upgrades shall mean Network Upgrades that the 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 Part A to this LGIA.

Standard Large Generator Interconnection Procedures (LGIP) shall mean 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.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, that protects (1) the Participating TO's Transmission System, Participating TO's Interconnection Facilities, ISO Controlled Grid, and Affected Systems from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the ISO Controlled Grid, Participating TO's Interconnection Facilities, and Affected Systems or on other delivery systems or other generating systems to which the ISO Controlled Grid is directly connected.

Transmission Control Agreement shall mean ISO FERC Electric Tariff No. 7.

Trial Operation shall mean the period during which the Interconnection Customer is engaged in on-site test operations and commissioning of an Electric Generating Unit prior to Commercial Operation.

ARTICLE 2. EFFECTIVE DATE, TERM AND TERMINATION

2.1 **Effective Date**. This LGIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. The ISO and Participating TO shall promptly file this LGIA with FERC upon execution in accordance with Article 3.1, if required.

2.2 **Term of Agreement**. Subject to the provisions of Article 2.3, this LGIA shall remain in effect for a period of ____ years from the Effective Date (***Term Specified in Individual Agreements to be ten (10) years or such other longer period as the Interconnection Customer may request***) and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice. This LGIA may be terminated by the Interconnection Customer after giving the ISO and the Participating TO ninety (90) Calendar Days advance written notice, or by the ISO and the Participating TO notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default. A Party may terminate this LGIA in accordance with Article 17.

2.3.3 Suspension of Work. This LGIA may be deemed terminated in accordance with Article 5.16.

2.3.4 Notwithstanding Articles 2.3.1, 2.3.2, and 2.3.3, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this LGIA, which notice has been accepted for filing by FERC.

2.4 Termination Costs. If this LGIA terminates pursuant to Article 2.3 above, the Interconnection Customer shall pay all costs incurred or irrevocably committed to be incurred in association with the Interconnection Customer's interconnection (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) and other expenses, including any Network Upgrades and Distribution Upgrades for which the Participating TO or ISO has incurred expenses or has irrevocably committed to incur expenses and has not been reimbursed by the Interconnection Customer, as of the date of the other Parties' receipt of the notice of termination, subject to the limitations set forth in this Article 2.4. Nothing in this Article 2.4 shall limit the Parties' rights under Article 17.

2.4.1 Notwithstanding the foregoing, in the event of termination by a Party, all Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. With respect to any portion of the Participating TO's Interconnection Facilities that have not yet been constructed or installed, the Participating TO shall to the extent possible and with the Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event the Interconnection Customer elects not to authorize such cancellation, the Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and the Participating TO shall deliver such material and equipment, and, if necessary, assign such contracts, to the Interconnection Customer as soon as practicable, at the Interconnection Customer's expense. To the extent that the Interconnection Customer has already paid the Participating TO for any or all such costs of materials or equipment not taken by the Interconnection Customer, the Participating TO shall promptly refund such amounts to the Interconnection Customer, less any costs, including penalties, incurred by the Participating TO to cancel any pending orders of or return such materials, equipment, or contracts.

2.4.2 The Participating TO may, at its option, retain any portion of such materials, equipment, or facilities that the Interconnection Customer chooses not to accept delivery of, in which case the Participating TO shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 **Disconnection**. Upon termination of this LGIA, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Participating TO's Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 **Survival**. This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Parties pursuant to this LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

ARTICLE 3. REGULATORY FILINGS AND ISO TARIFF COMPLIANCE

3.1 **Filing**. The Participating TO and the ISO shall file this LGIA (and any amendment hereto) with the appropriate Governmental Authority(ies), if required. The Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If the Interconnection Customer has executed this LGIA, or any amendment thereto, the Interconnection Customer shall reasonably cooperate with the Participating TO and ISO with respect to such filing and to provide any information reasonably requested by the Participating TO or ISO needed to comply with applicable regulatory requirements.

3.2 **Agreement Subject to ISO Tariff**. The Interconnection Customer will comply with all applicable provisions of the ISO Tariff, including the LGIP.

3.3 **Relationship Between this LGIA and the ISO Tariff.** With regard to rights and obligations between the Participating TO and the Interconnection Customer, if and to the extent a matter is specifically addressed by a provision of this LGIA (including any appendices, schedules or other attachments to this LGIA), the provisions of this LGIA shall govern. If and to the extent a provision of this LGIA is inconsistent with the ISO Tariff and dictates rights and obligations between the ISO and the Participating TO or the ISO and the Interconnection Customer, the ISO Tariff shall govern.

3.4 **Relationship Between this LGIA and the QF PGA.** With regard to the rights and obligations of a Qualifying Facility that has entered into a QF PGA with the ISO and has entered into this LGIA, if and to the extent a matter is specifically addressed by a provision of the QF PGA that is inconsistent with this LGIA, the terms of the QF PGA shall govern.

ARTICLE 4. SCOPE OF SERVICE

4.1 **Interconnection Service.** Interconnection Service allows the Interconnection Customer to connect the Large Generating Facility to the Participating TO's Transmission System and be eligible to deliver the Large Generating Facility's output using the available capacity of the ISO Controlled Grid. To the extent the Interconnection Customer wants to receive Interconnection Service, the Participating TO shall construct facilities identified in Appendices A and C that the Participating TO is responsible to construct.

Interconnection Service does not necessarily provide the Interconnection Customer with the capability to physically deliver the output of its Large Generating Facility to any particular load on the ISO Controlled Grid without incurring congestion costs. In the event of transmission constraints on the ISO Controlled Grid, the Interconnection Customer's Large Generating Facility shall be subject to the applicable congestion management procedures in the ISO Tariff in the same manner as all other resources.

4.2 **Provision of Service**. The Participating TO and the ISO shall provide Interconnection Service for the Large Generating Facility.

4.3 **Performance Standards**. Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is the ISO or Participating TO, then that Party shall amend the LGIA and submit the amendment to FERC for approval.

4.4 **No Transmission Service**. The execution of this LGIA does not constitute a request for, nor the provision of, any transmission service under the ISO Tariff, and does not convey any right to deliver electricity to any specific customer or point of delivery.

4.5 **Interconnection Customer Provided Services**. The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.6.

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

Interconnection Facilities, Network Upgrades, and Distribution Upgrades shall be studied, designed, and constructed pursuant to Good Utility Practice. Such studies, design and construction shall be based on the assumed accuracy and completeness of all technical information received by the Participating TO and the ISO from the Interconnection Customer associated with interconnecting the Large Generating Facility.

5.1 **Options**. Unless otherwise mutually agreed among the Parties, the Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either Standard Option or Alternate Option set forth below for completion of the Participating TO's Interconnection Facilities and Network Upgrades as set forth in Part A, Interconnection Facilities, Network Upgrades, and Distribution Upgrades, and such dates and selected option shall be set forth in Part B, Milestones.

5.1.1 **Standard Option**. The Participating TO shall design, procure, and construct the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades, using Reasonable Efforts to complete the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades by the dates set forth in Part B, Milestones. The Participating TO shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event the Participating TO reasonably expects that it will not be able to complete the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades by the specified dates, the Participating TO shall promptly provide written notice to the Interconnection Customer and the ISO and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 Alternate Option. If the dates designated by the Interconnection Customer are acceptable to the Participating TO, the Participating TO shall so notify the Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of the Participating TO's Interconnection Facilities by the designated dates.

If the Participating TO subsequently fails to complete the Participating TO's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Part B, Milestones; the Participating TO shall pay the Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by the Interconnection Customer shall be extended day for day for each day that the ISO refuses to grant clearances to install equipment.

5.1.3 Option to Build. If the dates designated by the Interconnection Customer are not acceptable to the Participating TO, the Participating TO shall so notify the Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, the Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades. If the Interconnection Customer elects to exercise its option to assume responsibility for the design, procurement and construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades, it shall so notify the Participating TO within thirty (30) Calendar Days of receipt of the Participating TO's notification that the designated dates are not acceptable to the Participating TO. The Participating TO, ISO, and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Part A to this LGIA. Except for Stand Alone Network Upgrades, the Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 Negotiated Option. If the Interconnection Customer elects not to exercise its option under Article 5.1.3, Option to Build, the Interconnection Customer shall so notify the Participating TO within thirty (30) Calendar Days of receipt of the Participating TO's notification that the designated dates are not acceptable to the Participating TO, and the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades by the Interconnection Customer) pursuant to which the Participating TO is responsible for the design, procurement and construction of the Participating TO's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, the Participating TO shall assume responsibility for the design, procurement and construction of the Participating TO's Interconnection Facilities and Network Upgrades pursuant to Article 5.1.1, Standard Option.

5.2 General Conditions Applicable to Option to Build. If the Interconnection Customer assumes responsibility for the design, procurement and construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades,

(1) the Interconnection Customer shall engineer, procure equipment, and construct the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by the Participating TO;

(2) The Interconnection Customer's engineering, procurement and construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which the Participating TO would be subject in the engineering, procurement or construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades;

(3) the Participating TO shall review, and the Interconnection Customer shall obtain the Participating TO's approval of, the engineering design, equipment acceptance tests, and the construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades, which approval shall not be unreasonably withheld, and the ISO may, at its option, review the engineering design, equipment acceptance tests, and the construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, the Interconnection Customer shall provide to the Participating TO, with a copy to the ISO for informational purposes, a schedule for construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from the Participating TO;

(5) at any time during construction, the Participating TO shall have the right to gain unrestricted access to the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by the Participating TO, the Interconnection Customer shall be obligated to remedy deficiencies in that portion of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades;

(7) the Interconnection Customer shall indemnify the ISO and Participating TO for claims arising from the Interconnection Customer's construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) The Interconnection Customer shall transfer control of the Participating TO's Interconnection Facilities to the Participating TO and shall transfer Operational Control of Stand Alone Network Upgrades to the ISO;

(9) Unless the Parties otherwise agree, the Interconnection Customer shall transfer ownership of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades to the Participating TO. As soon as reasonably practicable, but within twelve months after completion of the construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades, the Interconnection Customer shall provide an invoice of the final cost of the construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades to the Participating TO, which invoice shall set forth such costs in sufficient detail to enable the Participating TO to reflect the proper costs of such facilities in its transmission rate base and to identify the investment upon which refunds will be provided;

(10) the Participating TO shall accept for operation and maintenance the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) The Interconnection Customer's engineering, procurement and construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of the "Option to Build" conditions set forth in Part C. Interconnection Customer shall deliver to the Participating TO "as-built" drawings, information, and any other documents that are reasonably required by the Participating TO to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by the Participating TO.

5.3 **Liquidated Damages**. The actual damages to the Interconnection Customer, in the event the Participating TO's Interconnection Facilities or Network Upgrades are not completed by the dates designated by the Interconnection Customer and accepted by the Participating TO pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by the Participating TO to the Interconnection Customer in the event that the Participating TO does not complete any portion of the Participating TO's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of the Participating TO's Interconnection Facilities and Network Upgrades, in the aggregate, for which the Participating TO has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of the Participating TO's Interconnection Facilities and Network Upgrades for which the Participating TO has assumed responsibility to design, procure, and construct. The foregoing payments will be made by the Participating TO to the Interconnection Customer as just compensation for the damages caused to the Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Participating TO's failure to meet its schedule.

No liquidated damages shall be paid to the Interconnection Customer if: (1) the Interconnection Customer is not ready to commence use of the Participating TO's Interconnection Facilities or Network Upgrades to take the delivery of power for the Electric Generating Unit's Trial Operation or to export power from the Electric Generating Unit on the specified dates, unless the Interconnection Customer would have been able to commence use of the Participating TO's Interconnection Facilities or Network Upgrades to take the delivery of power for Electric Generating Unit's Trial Operation or to export power from the Electric Generating Unit, but for the Participating TO's delay; (2) the Participating TO's failure to meet the specified dates is the result of the action or inaction of the Interconnection Customer or any other interconnection customer who has entered into an interconnection agreement with the ISO and/or Participating TO, action or inaction by the ISO, or any cause beyond the Participating TO's reasonable control or reasonable ability to cure; (3) the Interconnection Customer has assumed responsibility for the design, procurement and construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

In no event shall the ISO have any responsibility or liability to the Interconnection Customer for liquidated damages pursuant to the provisions of this Article 5.3.

5.4 **Power System Stabilizers**. The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council and in accordance with the provisions of Section 5.4.1 of the ISO Tariff. The ISO reserves the right to establish reasonable minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, the Interconnection Customer shall immediately notify the ISO and the Participating TO and restore the Power System Stabilizers to operation as soon as possible and in accordance with the Reliability Management System Agreement in Part G. The ISO shall have the right to order the reduction in output or disconnection of the Large Generating Facility if the reliability of the ISO Controlled Grid would be adversely affected as a result of improperly tuned Power System Stabilizers. The requirements of this Article 5.4 shall not apply to wind generators of the induction type.

5.5 **Equipment Procurement**. If responsibility for construction of the Participating TO's Interconnection Facilities or Network Upgrades is to be borne by the Participating TO, then the Participating TO shall commence design of the Participating TO's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 The ISO, in coordination with the applicable Participating TO(s), has completed the Interconnection Facilities Study pursuant to the Interconnection Facilities Study Agreement;

5.5.2 The Participating TO has received written authorization to proceed with design and procurement from the Interconnection Customer by the date specified in Part B, Milestones; and

5.5.3 The Interconnection Customer has provided security to the Participating TO in accordance with Article 11.5 by the dates specified in Part B, Milestones.

5.6 **Construction Commencement**. The Participating TO shall commence construction of the Participating TO's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of the Participating TO's Interconnection Facilities and Network Upgrades;

5.6.3 The Participating TO has received written authorization to proceed with construction from the Interconnection Customer by the date specified in Part B, Milestones; and

5.6.4 The Interconnection Customer has provided payment and security to the Participating TO in accordance with Article 11.5 by the dates specified in Part B, Milestones.

5.7 Work Progress. The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Any Party may, at any time, request a progress report from another Party. If, at any time, the Interconnection Customer determines that the completion of the Participating TO's Interconnection Facilities will not be required until after the specified in-service date, the Interconnection Customer will provide written notice to the Participating TO and ISO of such later date upon which the completion of the Participating TO's Interconnection Facilities will be required.

5.8 Information Exchange. As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Interconnection Customer's Interconnection Facilities and Participating TO's Interconnection Facilities and compatibility of the Interconnection Facilities with the Participating TO's Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Limited Operation. If any of the Participating TO's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Electric Generating Unit, the Participating TO and/or ISO, as applicable, shall, upon the request and at the expense of the Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Electric Generating Unit and the Interconnection Customer's Interconnection Facilities may operate prior to the completion of the Participating TO's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. The Participating TO and ISO shall permit Interconnection Customer to operate the Electric Generating Unit and the Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.10 Interconnection Customer's Interconnection Facilities. The Interconnection Customer shall, at its expense, design, procure, construct, own and install the Interconnection Customer's Interconnection Facilities, as set forth in Part A.

5.10.1 Large Generating Facility and Interconnection Customer's Interconnection Facilities Specifications. The Interconnection Customer shall submit initial specifications for the Interconnection Customer's Interconnection Facilities and Large Generating Facility, including System Protection Facilities, to the Participating TO and the ISO at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. The Participating TO and the ISO shall review such specifications pursuant to this LGIA and the LGIP to ensure that the Interconnection Customer's Interconnection Facilities and Large Generating Facility are compatible with the technical specifications, operational control, safety requirements, and any other applicable requirements of the Participating TO and the ISO and comment on such specifications within thirty (30) Calendar Days of the Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Participating TO's and ISO's Review. The Participating TO's and the ISO's review of the Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall make such changes to the Interconnection Customer's Interconnection Facilities as may reasonably be required by the Participating TO or the ISO, in accordance with Good Utility Practice, to ensure that the Interconnection Customer's Interconnection Facilities are compatible with the technical specifications, Operational Control, and safety requirements of the Participating TO or the ISO.

5.10.3 Interconnection Customer's Interconnection Facilities Construction. The Interconnection Customer's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Participating TO and Interconnection Customer agree on another mutually acceptable deadline, the Interconnection Customer shall deliver to the Participating TO and ISO "as-built" drawings, information and documents for the Interconnection Customer's Interconnection Facilities and the Electric Generating Unit(s), such as: a one-line diagram, a site plan showing the Large Generating Facility and the Interconnection Customer's Interconnection Facilities, plan and elevation drawings showing the layout of the Interconnection Customer's Interconnection Facilities, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with the Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the Interconnection Customer's Interconnection Facilities, and the impedances (determined by factory tests) for the associated step-up transformers and the Electric Generating Units. The Interconnection Customer shall provide the Participating TO and the ISO specifications for the excitation system, automatic voltage regulator, Large Generating Facility control and protection settings, transformer tap settings, and communications, if applicable. Any deviations from the relay settings, machine specifications, and other specifications originally submitted by the Interconnection Customer shall be assessed by the Participating TO and the ISO pursuant to the appropriate provisions of this LGIA and the LGIP.

5.10.4 Interconnection Customer to Meet Requirements of the Participating TO's Interconnection Handbook. The Interconnection Customer shall comply with the Participating TO's Interconnection Handbook.

5.11 Participating TO's Interconnection Facilities Construction. The Participating TO's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Participating TO and Interconnection Customer agree on another mutually acceptable deadline, the Participating TO shall deliver to the Interconnection Customer and the ISO the following "as-built" drawings, information and documents for the Participating TO's Interconnection Facilities.

The Participating TO will obtain control for operating and maintenance purposes of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities. Pursuant to Article 5.2, the ISO will obtain Operational Control of the Stand Alone Network Upgrades prior to the Commercial Operation Date.

5.12 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish *at no cost* to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Participating TO's Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the Participating TO's Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of the Participating TO's Interconnection Facilities and/or Network Upgrades are to be installed on property owned by persons other than the Interconnection Customer or Participating TO, the Participating TO shall at the Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove the Participating TO's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 Permits. Participating TO and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses and authorization that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, the Participating TO shall provide permitting assistance to the Interconnection Customer comparable to that provided to the Participating TO's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities. The Interconnection Customer may request the Participating TO to construct, and the Participating TO shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Participating TO's Transmission System which are included in the Base Case of the Interconnection Studies for the Interconnection Customer, and which also are required to be constructed for another interconnection customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Suspension. The Interconnection Customer reserves the right, upon written notice to the Participating TO and the ISO, to suspend at any time all work associated with the construction and installation of the Participating TO's Interconnection Facilities, Network Upgrades, and/or Distribution Upgrades required under this LGIA with the condition that the Participating TO's electrical system and the ISO Controlled Grid shall be left in a safe and reliable condition in accordance with Good Utility Practice and the Participating TO's safety and reliability criteria and the ISO's Applicable Reliability Standards. In such event, the Interconnection Customer shall be responsible for all reasonable and necessary costs which the Participating TO (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Participating TO's electric system during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which the Participating TO cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, the Participating TO shall obtain Interconnection Customer's authorization to do so.

The Participating TO shall invoice the Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work required under this LGIA pursuant to this Article 5.16, and has not requested the Participating TO to recommence the work or has not itself recommenced work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to the Participating TO and the ISO, if no effective date is specified.

5.17 Taxes.

5.17.1 Interconnection Customer Payments Not Taxable. The Parties intend that all payments or property transfers made by the Interconnection Customer to the Participating TO for the installation of the Participating TO's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as a refundable advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 Representations And Covenants. In accordance with IRS Notice 2001-82 and IRS Notice 88-129, the Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the ISO Controlled Grid, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to the Participating TO for the Participating TO's Interconnection Facilities will be capitalized by the Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of the Participating TO's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At the Participating TO's request, the Interconnection Customer shall provide the Participating TO with a report from an independent engineer confirming its representation in clause (iii), above. The Participating TO represents and covenants that the cost of the Participating TO's Interconnection Facilities paid for by the Interconnection Customer without the possibility of refund or credit will have no net effect on the base upon which rates are determined.

5.17.3 Indemnification for the Cost Consequence of Current Tax Liability Imposed Upon the Participating TO. Notwithstanding Article 5.17.1, the Interconnection Customer shall protect, indemnify and hold harmless the Participating TO from the cost consequences of any current tax liability imposed against the Participating TO as the result of payments or property transfers made by the Interconnection Customer to the Participating TO under this LGIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by the Participating TO.

The Participating TO shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges the Interconnection Customer under this LGIA unless (i) the Participating TO has determined, in good faith, that the payments or property transfers made by the Interconnection Customer to the Participating TO should be reported as income subject to taxation or (ii) any Governmental Authority directs the Participating TO to report payments or property as income subject to taxation; provided, however, that the Participating TO may require the Interconnection Customer to provide security for Interconnection Facilities, in a form reasonably acceptable to the Participating TO (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. The Interconnection Customer shall reimburse the Participating TO for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from the Participating TO of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by the Participating TO upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 Tax Gross-Up Amount. The Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that the Interconnection Customer will pay the Participating TO, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on the Participating TO ("Current Taxes") on the excess of (a) the gross income realized by the Participating TO as a result of payments or property transfers made by the Interconnection Customer to the Participating TO under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit the Participating TO to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on the Participating TO's composite federal and state tax rates at the time the payments or property transfers are received and the Participating TO will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting the Participating TO's anticipated tax depreciation deductions as a result of such payments or property transfers by the Participating TO's current weighted average cost of capital. Thus, the formula for calculating the Interconnection Customer's liability to the Participating TO pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Part A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 Private Letter Ruling or Change or Clarification of Law. At the Interconnection Customer's request and expense, the Participating TO shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by the Interconnection Customer to the Participating TO under this LGIA are subject to federal income taxation. The Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of the Interconnection Customer's knowledge. The Participating TO and Interconnection Customer shall cooperate in good faith with respect to the submission of such request, provided, however, the Interconnection Customer and the Participating TO explicitly acknowledge (and nothing herein is intended to alter) Participating TO's obligation under law to certify that the facts presented in the ruling request are true, correct and complete.

The Participating TO shall keep the Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes the Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. The Participating TO shall allow the Interconnection Customer to attend all meetings with IRS officials about the request and shall permit the Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 Subsequent Taxable Events. If, within 10 years from the date on which the relevant Participating TO's Interconnection Facilities are placed in service, (i) the Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this LGIA terminates and the Participating TO retains ownership of the Interconnection Facilities and Network Upgrades, the Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on the Participating TO, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 Contests. In the event any Governmental Authority determines that the Participating TO's receipt of payments or property constitutes income that is subject to taxation, the Participating TO shall notify the Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by the Interconnection Customer and at the Interconnection Customer's sole expense, the Participating TO may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon the Interconnection Customer's written request and sole expense, the Participating TO may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. The Participating TO reserve the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but the Participating TO shall keep the Interconnection Customer informed, shall consider in good faith suggestions from the Interconnection Customer about the conduct of the contest, and shall reasonably permit the Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

The Interconnection Customer shall pay to the Participating TO on a periodic basis, as invoiced by the Participating TO, the Participating TO's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest, including any costs associated with obtaining the opinion of independent tax counsel described in this Article 5.17.7. The Participating TO may abandon any contest if the Interconnection Customer fails to provide payment to the Participating TO within thirty (30) Calendar Days of receiving such invoice.

At any time during the contest, the Participating TO may agree to a settlement either with the Interconnection Customer's consent or, if such consent is refused, after obtaining written advice from independent nationally-recognized tax counsel, selected by the Participating TO, but reasonably acceptable to the Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. The Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by the Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding paragraph. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. The Participating TO may also settle any tax controversy without receiving the Interconnection Customer's consent or any such written advice; however, any such settlement will relieve the Interconnection Customer from any obligation to indemnify the Participating TO for the tax at issue in the contest (unless the failure to obtain written advice is attributable to the Interconnection Customer's unreasonable refusal to the appointment of independent tax counsel).

5.17.8 Refund. In the event that (a) a private letter ruling is issued to the Participating TO which holds that any amount paid or the value of any property transferred by the Interconnection Customer to the Participating TO under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to the Participating TO in good faith that any amount paid or the value of any property transferred by the Interconnection Customer to the Participating TO under the terms of this LGIA is not taxable to the Participating TO, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by the Interconnection Customer to the Participating TO are not subject to federal income tax, or (d) if the Participating TO receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by the Interconnection Customer to the Participating TO pursuant to this LGIA, the Participating TO shall promptly refund to the Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by the Interconnection Customer to the Participating TO for such taxes which the Participating TO did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. §35.19a(a)(2)(iii) from the date payment was made by the Interconnection Customer to the date the Participating TO refunds such payment to the Interconnection Customer, and

(iii) with respect to any such taxes paid by the Participating TO, any refund or credit the Participating TO receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to the Participating TO for such overpayment of taxes (including any reduction in interest otherwise payable by the Participating TO to any Governmental Authority resulting from an offset or credit); provided, however, that the Participating TO will remit such amount promptly to the Interconnection Customer only after and to the extent that the Participating TO has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to the Participating TO's Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 Taxes Other Than Income Taxes. Upon the timely request by the Interconnection Customer, and at the Interconnection Customer's sole expense, the ISO or Participating TO may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against the ISO or Participating TO for which the Interconnection Customer may be required to reimburse the ISO or Participating TO under the terms of this LGIA. The Interconnection Customer shall pay to the Participating TO on a periodic basis, as invoiced by the Participating TO, the Participating TO's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. The Interconnection Customer, the ISO, and the Participating TO shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by the Interconnection Customer to the ISO or Participating TO for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, the Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by the Participating TO.

5.18 Tax Status. Each Party shall cooperate with the others to maintain the other Parties' tax status. Nothing in this LGIA is intended to adversely affect the ISO's or any Participating TO's tax exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. The Interconnection Customer or the Participating TO may undertake modifications to its facilities, subject to the provisions of this LGIA and the ISO Tariff. If a Party plans to undertake a modification that reasonably may be expected to affect the other Parties' facilities, that Party shall provide to the other Parties sufficient information regarding such modification so that the other Parties may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Parties at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Large Generating Facility modifications that do not require the Interconnection Customer to submit an Interconnection Request, the ISO or Participating TO shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the ISO Controlled Grid, Participating TO's Interconnection Facilities, Network Upgrades or Distribution Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof. The Participating TO and the ISO shall determine if a Large Generating Facility modification is a Material Modification in accordance with the LGIP.

5.19.2 Standards. Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 Modification Costs. The Interconnection Customer shall not be directly assigned the costs of any additions, modifications, or replacements that the Participating TO makes to the Participating TO's Interconnection Facilities or the Participating TO's Transmission System to facilitate the interconnection of a third party to the Participating TO's Interconnection Facilities or the Participating TO's Transmission System, or to provide transmission service to a third party under the ISO Tariff. The Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to the Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

ARTICLE 6. TESTING AND INSPECTION

6.1 Pre-Commercial Operation Date Testing and Modifications. Prior to the Commercial Operation Date, the Participating TO shall test the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades and the Interconnection Customer shall test the Large Generating Facility and the Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. The Interconnection Customer shall bear the cost of all such testing and modifications. The Interconnection Customer shall not commence initial parallel operation of an Electric Generating Unit with the Participating TO's Transmission System until the Participating TO provides prior written approval, which approval shall not be unreasonably withheld, for operation of such Electric Generating Unit. The Interconnection Customer shall generate test energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Large Generating Facility with the Participating TO's Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 Right to Observe Testing. Each Party shall notify the other Parties at least fourteen (14) days in advance of its performance of tests of its Interconnection Facilities or Generating Facility. The other Parties have the right, at their own expense, to observe such testing.

6.4 **Right to Inspect**. Each Party shall have the right, but shall have no obligation to: (i) observe another Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of another Party's System Protection Facilities and other protective equipment; and (iii) review another Party's maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this LGIA.

ARTICLE 7. METERING

7.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. The Interconnection Customer and ISO shall comply with the provisions of the ISO Tariff regarding metering, including Section 10 and the Metering Protocol of the ISO Tariff. Unless otherwise agreed by the Participating TO and the Interconnection Customer, the Participating TO may install additional Metering Equipment at the Point of Interconnection prior to any operation of any Electric Generating Unit and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Large Generating Facility shall be measured at or, at the ISO's or Participating TO's option for its respective Metering Equipment, compensated to, the Point of Interconnection. The ISO shall provide metering quantities to the Interconnection Customer upon request in accordance with the ISO Tariff by directly polling the ISO's meter data acquisition system. The Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 **Check Meters**. The Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check the ISO-polled meters or the Participating TO's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except in the case that no other means are available on a temporary basis at the option of the ISO or the Participating TO. The check meters shall be subject at all reasonable times to inspection and examination by the ISO or Participating TO or their designees. The installation, operation and maintenance thereof shall be performed entirely by the Interconnection Customer in accordance with Good Utility Practice.

7.3 **Participating TO Retail Metering**. The Participating TO may install retail revenue quality meters and associated equipment, pursuant to the Participating TO's applicable retail tariffs.

ARTICLE 8. COMMUNICATIONS

8.1 **Interconnection Customer Obligations**. The Interconnection Customer shall maintain satisfactory operating communications with the ISO in accordance with the provisions of the ISO Tariff and with the Participating TO's dispatcher or representative designated by the Participating TO. The Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Large Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. The Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to the ISO and Participating TO as set forth in Part D, Security Arrangements Details. The data circuit(s) shall extend from the Large Generating Facility to the location(s) specified by the ISO and Participating TO. Any required maintenance of such communications equipment shall be performed by the Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 **Remote Terminal Unit**. Prior to the Initial Synchronization Date of each Electric Generating Unit, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by the Interconnection Customer, or by the Participating TO at the Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by the ISO and by the Participating TO through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1.

Telemetry to the ISO shall be provided in accordance with the ISO's technical standards for direct telemetry. For telemetry to the Participating TO, the communication protocol for the data circuit(s) shall be specified by the Participating TO. Instantaneous bi-directional real power and reactive power flow and any other required information must be telemetered directly to the location(s) specified by the Participating TO.

Each Party will promptly advise the other Parties if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by another Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 **No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

ARTICLE 9. OPERATIONS

9.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements, and the Interconnection Customer shall execute the Reliability Management System Agreement of the Applicable Reliability Council attached hereto as Part G. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 Control Area Notification. At least three months before Initial Synchronization Date, the Interconnection Customer shall notify the ISO and Participating TO in writing of the Control Area in which the Large Generating Facility intends to be located. If the Interconnection Customer intends to locate the Large Generating Facility in a Control Area other than the Control Area within whose electrically metered boundaries the Large Generating Facility is located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area.

9.3 ISO and Participating TO Obligations. The ISO and Participating TO shall cause the Participating TO's Transmission System to be operated and controlled in a safe and reliable manner and in accordance with this LGIA. The Participating TO at the Interconnection Customer's expense shall cause the Participating TO's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA. The ISO and Participating TO may provide operating instructions to the Interconnection Customer consistent with this LGIA and Participating TO and ISO operating protocols and procedures as they may change from time to time. The Participating TO and ISO will consider changes to their operating protocols and procedures proposed by the Interconnection Customer.

9.4 Interconnection Customer Obligations. The Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA. The Interconnection Customer shall operate the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, including such requirements as set forth in Part C, Interconnection Details, of this LGIA. Part C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. A Party may request that another Party provide copies of the requirements set forth in Part C, Interconnection Details, of this LGIA. The Interconnection Customer shall not commence Commercial Operation of an Electric Generating Unit with the Participating TO's Transmission System until the Participating TO provides prior written approval, which approval shall not be unreasonably withheld, for operation of such Electric Generating Unit.

9.5 Start-Up and Synchronization. Consistent with the Parties' mutually acceptable procedures, the Interconnection Customer is responsible for the proper synchronization of each Electric Generating Unit to the ISO Controlled Grid.

9.6 Reactive Power.

9.6.1 Power Factor Design Criteria. The Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the terminals of the Electric Generating Unit at a power factor within the range of 0.95 leading to 0.90 lagging, unless the ISO has established different requirements that apply to all generators in the Control Area on a comparable basis. Power factor design criteria for wind generators are provided in Part H of this LGIA.

9.6.2 Voltage Schedules. Once the Interconnection Customer has synchronized an Electric Generating Unit with the ISO Controlled Grid, the ISO or Participating TO shall require the Interconnection Customer to maintain a voltage schedule by operating the Electric Generating Unit to produce or absorb reactive power within the design limitations of the Electric Generating Unit set forth in Article 9.6.1 (Power Factor Design Criteria). ISO's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. The Participating TO shall exercise Reasonable Efforts to provide the Interconnection Customer with such schedules at least one (1) day in advance, and the ISO or Participating TO may make changes to such schedules as necessary to maintain the reliability of the ISO Controlled Grid or the Participating TO's electric system. The Interconnection Customer shall operate the Electric Generating Unit to maintain the specified output voltage or power factor within the design limitations of the Electric Generating Unit set forth in Article 9.6.1 (Power Factor Design Criteria), and as may be required by the ISO to operate the Electric Generating Unit at a specific voltage schedule within the design limitations set forth in Article 9.6.1. If the Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the ISO and the Participating TO.

9.6.2.1 Governors and Regulators. Whenever an Electric Generating Unit is operated in parallel with the ISO Controlled Grid and the speed governors (if installed on the Electric Generating Unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, the Interconnection Customer shall operate the Electric Generating Unit with its speed governors and voltage regulators in automatic operation. If the Electric Generating Unit's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify the ISO and the Participating TO and ensure that the Electric Generating Unit operates as specified in Article 9.6.2 through manual operation and that such Electric Generating Unit's reactive power production or absorption (measured in MVARs) are within the design capability of the Electric Generating Unit(s) and steady state stability limits. The Interconnection Customer shall restore the speed governors and voltage regulators to automatic operation as soon as possible and in accordance with the Reliability Management System Agreement in Part G. If the Large Generating Facility's speed governors and voltage regulators are improperly tuned or malfunctioning, the ISO shall have the right to order the reduction in output or disconnection of the Large Generating Facility if the reliability of the ISO Controlled Grid would be adversely affected. The Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the ISO Controlled Grid or trip any Electric Generating Unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Control Area on a comparable basis.

9.6.3 Payment for Reactive Power. ISO is required to pay the Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from an Electric Generating Unit when the ISO requests the Interconnection Customer to operate its Electric Generating Unit outside the range specified in Article 9.6.1, provided that if the ISO pays other generators for reactive power service within the specified range, it must also pay the Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the ISO and Interconnection Customer have otherwise agreed.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. Each Party may in accordance with Good Utility Practice in coordination with the other Parties remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact another Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to all Parties. In all circumstances any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Parties of such removal.

9.7.1.2 Outage Schedules. The ISO shall post scheduled outages of ISO Controlled Grid facilities in accordance with the provisions of the ISO Tariff. The Interconnection Customer shall submit its planned maintenance schedules for the Large Generating Facility to the ISO in accordance with the ISO Tariff. The Interconnection Customer shall update its planned maintenance schedules in accordance with the ISO Tariff. The ISO may request the Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the ISO Controlled Grid in accordance with the ISO Tariff. Such planned maintenance schedules and updates and changes to such schedules shall be provided by the Interconnection Customer to the Participating TO concurrently with their submittal to the ISO. The ISO shall compensate the Interconnection Customer for any additional direct costs that the Interconnection Customer incurs as a result of having to reschedule maintenance in accordance with the ISO Tariff. The Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, the Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 Outage Restoration. If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects another Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Parties, to the extent such information is known, information on the nature of the Emergency Condition, if the outage is caused by an Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage, if requested by a Party, which may be provided by e-mail or facsimile.

9.7.2 Interruption of Service. If required by Good Utility Practice to do so, the ISO or the Participating TO may require the Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect the ISO's or the Participating TO's ability to perform such activities as are necessary to safely and reliably operate and maintain the Participating TO's electric system or the ISO Controlled Grid. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the ISO Controlled Grid, subject to any conditions specified in this LGIA;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, the ISO or Participating TO, as applicable, shall notify the Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification, if requested by the Interconnection Customer, as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, the ISO or Participating TO shall notify the Interconnection Customer in advance regarding the timing of such interruption or reduction and further notify the Interconnection Customer of the expected duration. The ISO or Participating TO shall coordinate with the Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to the Interconnection Customer, the ISO, and the Participating TO;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Large Generating Facility, Interconnection Facilities, the Participating TO's Transmission System, and the ISO Controlled Grid to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 Under-Frequency and Over Frequency Conditions. The ISO Controlled Grid is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. The Interconnection Customer shall implement under-frequency and over-frequency protection set points for the Large Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with the Participating TO and ISO in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the ISO Controlled Grid during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 System Protection Facilities. The Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities. The Participating TO shall install at the Interconnection Customer's expense any System Protection Facilities that may be required on the Participating TO's Interconnection Facilities or the Participating TO's Transmission System as a result of the interconnection of the Large Generating Facility and the Interconnection Customer's Interconnection Facilities.

9.7.4.2 The Participating TO's and Interconnection Customer's protection facilities shall be designed and coordinated with other systems in accordance with Applicable Reliability Council criteria and Good Utility Practice.

9.7.4.3 The Participating TO and Interconnection Customer shall each be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 The Participating TO's and Interconnection Customer's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of the Interconnection Customer's Electric Generating Units.

9.7.4.5 The Participating TO and Interconnection Customer will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice and, if applicable, the requirements of the Participating TO's Interconnection Handbook.

9.7.4.6 Prior to the in-service date, and again prior to the Commercial Operation Date, the Participating TO and Interconnection Customer or their agents shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice, the standards and procedures of the Participating TO, including, if applicable, the requirements of the Participating TO's Interconnection Handbook, and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 Requirements for Protection. In compliance with Good Utility Practice and, if applicable, the requirements of the Participating TO's Interconnection Handbook, the Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the Participating TO's Transmission System not otherwise isolated by the Participating TO's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Participating TO's Transmission System. Such protective equipment shall include, without limitation, a disconnecting device with fault current-interrupting capability located between the Large Generating Facility and the Participating TO's Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. The Interconnection Customer shall be responsible for protection of the Large Generating Facility and the Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. The Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and the Interconnection Customer's other equipment if conditions on the ISO Controlled Grid could adversely affect the Large Generating Facility.

9.7.6 Power Quality. Neither the Participating TO's nor the Interconnection Customer's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, any applicable superseding electric industry standard, or any alternative Applicable Reliability Council standard. In the event of a conflict between ANSI Standard C84.1-1989, any applicable superseding electric industry standard, or any alternative Applicable Reliability Council standard, the alternative Applicable Reliability Council standard shall control.

9.8 Switching and Tagging Rules. Each Party shall provide the other Parties a copy of its switching and tagging rules that are applicable to the other Parties' activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Participating TO's Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use the Participating TO's Interconnection Facilities, or any part thereof, the Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by the Participating TO, all third party users, and the Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between the Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by the Participating TO, all third party users, and the Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or the ISO Controlled Grid by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

ARTICLE 10. MAINTENANCE

10.1 Participating TO Obligations. The Participating TO shall maintain the Participating TO's Transmission System and the Participating TO's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.2 Interconnection Customer Obligations. The Interconnection Customer shall maintain the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.3 Coordination. The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Large Generating Facility and the Interconnection Facilities.

10.4 Secondary Systems. The Participating TO and Interconnection Customer shall cooperate with the other Parties in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Parties. Each Party shall provide advance notice to the other Parties before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

10.5 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, the Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing the Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of the Participating TO's Interconnection Facilities.

ARTICLE 11. PERFORMANCE OBLIGATION

11.1 Interconnection Customer's Interconnection Facilities. The Interconnection Customer shall design, procure, construct, install, own and/or control the Interconnection Customer's Interconnection Facilities described in Part A at its sole expense.

11.2 Participating TO's Interconnection Facilities. The Participating TO shall design, procure, construct, install, own and/or control the Participating TO's Interconnection Facilities described in Part A at the sole expense of the Interconnection Customer. Unless the Participating TO elects to fund the capital for the Participating TO's Interconnection Facilities, they shall be solely funded by the Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades. The Participating TO shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Part A. The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless the Participating TO elects to fund the capital for the Distribution Upgrades and Network Upgrades, they shall be solely funded by the Interconnection Customer.

11.4 Transmission Credits. No later than thirty (30) days prior to the Commercial Operation Date, the Interconnection Customer may make a one-time election by written notice to the ISO and the Participating TO to receive Firm Transmission Rights as defined in and as available under the ISO Tariff at the time of the election in accordance with the ISO Tariff, in lieu of a refund of the cost of Network Upgrades in accordance with Article 11.4.1.

11.4.1 Repayment of Amounts Advanced for Network Upgrades. Upon the Commercial Operation Date, the Interconnection Customer shall be entitled to a repayment, equal to the total amount paid to the Participating TO for the cost of Network Upgrades. Such amount shall include any tax gross-up or other tax-related payments associated with Network Upgrades not refunded to the Interconnection Customer pursuant to Article 5.17.8 or otherwise, and shall be paid to the Interconnection Customer by the Participating TO on a dollar-for-dollar basis either through (1) direct payments made on a levelized basis over the five-year period commencing on the Commercial Operation Date; or (2) any alternative payment schedule that is mutually agreeable to the Interconnection Customer and Participating TO, provided that such amount is paid within five (5) years from the Commercial Operation Date. Notwithstanding the foregoing, if this LGIA terminates within five (5) years from the Commercial Operation Date, the Participating TO's obligation to pay refunds to the Interconnection Customer shall cease as of the date of termination. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. §35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment. Interest shall continue to accrue on the repayment obligation so long as this LGIA is in effect. The Interconnection Customer may assign such repayment rights to any person.

If the Large Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, the Participating TO shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which reimbursement must be made.

11.4.2 **Special Provisions for Affected Systems**. The Interconnection Customer shall enter into an agreement with the owner of the Affected System and/or other affected owners of portions of the ISO Controlled Grid, as applicable, in accordance with the LGIP. Such agreement shall specify the terms governing payments to be made by the Interconnection Customer to the owner of the Affected System and/or other affected owners of portions of the ISO Controlled Grid as well as the repayment by the owner of the Affected System and/or other affected owners of portions of the ISO Controlled Grid. In no event shall the Participating TO be responsible for the repayment for any facilities that are not part of the Participating TO's Transmission System.

11.4.3 Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that the Interconnection Customer shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Large Generating Facility.

11.5 **Provision of Security**. At least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of a Participating TO's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, the Interconnection Customer shall provide the Participating TO, at the Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to the Participating TO and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment shall be in an amount sufficient to cover the costs for constructing, procuring and installing the applicable portion of the Participating TO's Interconnection Facilities, Network Upgrades, or Distribution Upgrades. Such security shall be reduced on a dollar-for-dollar basis for payments made to the Participating TO for these purposes.

In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of the Participating TO, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to the Participating TO and must specify a reasonable expiration date.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to the Participating TO and must specify a reasonable expiration date.

11.6 **Interconnection Customer Compensation**. If the ISO requests or directs the Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power) or 13.5.1 of this LGIA, the ISO shall compensate the Interconnection Customer in accordance with the ISO Tariff.

11.6.1 Interconnection Customer Compensation for Actions During Emergency Condition. The ISO shall compensate the Interconnection Customer in accordance with the ISO Tariff for its provision of real and reactive power and other Emergency Condition services that the Interconnection Customer provides to support the ISO Controlled Grid during an Emergency Condition in accordance with Article 11.6.

ARTICLE 12. INVOICE

12.1 General. The Participating TO shall submit to the Interconnection Customer, on a monthly basis, invoices of amounts due pursuant to this LGIA for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party. Notwithstanding the foregoing, any invoices between the ISO and another Party shall be submitted and paid in accordance with the ISO Tariff.

12.2 Final Invoice. As soon as reasonably practicable, but within twelve months after completion of the construction of the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades, the Participating TO shall provide an invoice of the final cost of the construction of the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades, and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. The Participating TO shall refund to the Interconnection Customer any amount by which the actual payment by the Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice; or, in the event the actual costs of construction exceed the Interconnection Customer's actual payment for estimated costs, then the Interconnection Customer shall pay to the Participating TO any amount by which the actual costs of construction exceed the actual payment by the Interconnection Customer for estimated costs within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the Interconnection Customer at the address specified in Part F. The Interconnection Customer shall pay, or Participating TO shall refund, the amounts due within thirty (30) Calendar Days of the Interconnection Customer's receipt of the invoice. All payments shall be made in immediately available funds payable to the Interconnection Customer or Participating TO, or by wire transfer to a bank named and account designated by the invoicing Interconnection Customer or Participating TO. Payment of invoices by any Party will not constitute a waiver of any rights or claims any Party may have under this LGIA.

12.4 Disputes. In the event of a billing dispute between the Interconnection Customer and the Participating TO, the Participating TO and the ISO shall continue to provide Interconnection Service under this LGIA as long as the Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to the Participating TO or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Interconnection Customer fails to meet these two requirements for continuation of service, then the Participating TO may provide notice to the Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accordance with the methodology set forth in FERC's Regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Notwithstanding the foregoing, any billing dispute between the ISO and another Party shall be resolved in accordance with the provisions of Article 27 of this LGIA.

ARTICLE 13. EMERGENCIES

13.1 [Reserved]

13.2 Obligations. Each Party shall comply with the Emergency Condition procedures of the ISO, NERC, the Applicable Reliability Council, Applicable Laws and Regulations, and any emergency procedures set forth in this LGIA.

13.3 Notice. The Participating TO or the ISO shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects the Participating TO's Interconnection Facilities or Distribution System or the ISO Controlled Grid, respectively, that may reasonably be expected to affect the Interconnection Customer's operation of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities. The Interconnection Customer shall notify the Participating TO and the ISO promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or the Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the ISO Controlled Grid or the Participating TO's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of the Interconnection Customer's or Participating TO's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice, if requested by a Party, which may be provided by electronic mail or facsimile, or in the case of the ISO may be publicly posted on the ISO's internet web site.

13.4 Immediate Action. Unless, in the Interconnection Customer's reasonable judgment, immediate action is required, the Interconnection Customer shall obtain the consent of the ISO and the Participating TO, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or the Interconnection Customer's Interconnection Facilities in response to an Emergency Condition declared by the Participating TO or ISO or in response to any other emergency condition.

13.5 ISO and Participating TO Authority.

13.5.1 General. The ISO and Participating TO may take whatever actions or inactions, including issuance of dispatch instructions, with regard to the ISO Controlled Grid or the Participating TO's Interconnection Facilities or Distribution System they deem necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the ISO Controlled Grid or the Participating TO's Interconnection Facilities or Distribution System, and (iii) limit or prevent damage, and (iv) expedite restoration of service.

The Participating TO and the ISO shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or the Interconnection Customer's Interconnection Facilities. The Participating TO or the ISO may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing the Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing the Interconnection Customer to assist with black start (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of the ISO's and Participating TO's operating instructions concerning Large Generating Facility real power and reactive power output within the

manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 Reduction and Disconnection. The Participating TO or the ISO may reduce Interconnection Service or disconnect the Large Generating Facility or the Interconnection Customer's Interconnection Facilities when such reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of the ISO pursuant to the ISO Tariff. When the ISO or Participating TO can schedule the reduction or disconnection in advance, the ISO or Participating TO shall notify the Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. The ISO or Participating TO shall coordinate with the Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to the Interconnection Customer and the ISO and Participating TO. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the ISO Controlled Grid to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.6 Interconnection Customer Authority. Consistent with Good Utility Practice, this LGIA, and the ISO Tariff, the Interconnection Customer may take actions or inactions with regard to the Large Generating Facility or the Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the ISO Controlled Grid and the Participating TO's Interconnection Facilities. The ISO and Participating TO shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 Limited Liability. Except as otherwise provided in Article 11.6.1 of this LGIA, no Party shall be liable to any other Party for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

ARTICLE 14. REGULATORY REQUIREMENTS AND GOVERNING LAW

14.1 Regulatory Requirements. Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require the Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act or the Public Utility Holding Company Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

ARTICLE 15. NOTICES

15.1 General. Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by a Party to another and any instrument required or permitted to be tendered or delivered by a Party in writing to another shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Part F, Addresses for Delivery of Notices and Billings.

A Party must update the information in Part F as information changes. A Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change. Such changes shall not constitute an amendment to this LGIA.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Part F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to another and not required by this LGIA to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out in Part F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Parties in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

ARTICLE 16. FORCE MAJEURE

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 No Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this Article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

ARTICLE 17. DEFAULT

17.1 Default

17.1.1 General. No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act or omission of the other Party. Upon a Breach, the affected non-Breaching Party(ies) shall give written notice of such Breach to the Breaching Party. Except as provided in Article 17.1.2, the Breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the Breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 Right to Terminate. If a Breach is not cured as provided in this Article, or if a Breach is not capable of being cured within the period provided for herein, the affected non-Breaching Party(ies) shall have the right to declare a Default and terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not such Party(ies) terminates this LGIA, to recover from the Breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this Article will survive termination of this LGIA.

ARTICLE 18. INDEMNITY, CONSEQUENTIAL DAMAGES AND INSURANCE

18.1 Indemnity. Each Party shall at all times indemnify, defend, and hold the other Parties harmless from, any and all Losses arising out of or resulting from another Party's action or inactions of its obligations under this LGIA on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnified Party.

18.1.1 Indemnified Party. If an Indemnified Party is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the Indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such Indemnified Party may at the expense of the Indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 Indemnifying Party. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Party harmless under this Article 18, the amount owing to the Indemnified Party shall be the amount of such Indemnified Party’s actual Loss, net of any insurance or other recovery.

18.1.3 Indemnity Procedures. Promptly after receipt by an Indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Party shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Party. If the defendants in any such action include one or more Indemnified Parties and the Indemnifying Party and if the Indemnified Party reasonably concludes that there may

be legal defenses available to it and/or other Indemnified Parties which are different from or additional to those available to the Indemnifying Party, the Indemnified Party shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Party or Indemnified Parties having such differing or additional legal defenses.

The Indemnified Party shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Party and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Party, or there exists a conflict or adversity of interest between the Indemnified Party and the Indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Party, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Party, which shall not be unreasonably withheld, conditioned or delayed.

18.2 **Consequential Damages**. Other than the liquidated damages heretofore described in Article 5.3, in no event shall any Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 **Insurance**. Each Party shall, at its own expense, maintain in force throughout the period of this LGIA, and until released by the other Parties, the following minimum insurance coverages, with insurers rated no less than A- (with a minimum size rating of VII) by Bests' Insurance Guide and Key Ratings and authorized to do business in the state where the Point of Interconnection is located, except in the case of the ISO, the State of California:

18.3.1 Employer's Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located, except in the case of the ISO, the State of California.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Business Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employer's Liability Commercial General Liability and Business Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Business Automobile Insurance and Excess Public Liability Insurance policies shall name the other Parties, their parents, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Business Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Business Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) Calendar Days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) Calendar Days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior unsecured debt or issuer rating is BBB-, or better, as rated by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior unsecured debt rating and issuer rating are both unrated by Standard & Poor's or are both rated at less than BBB- by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this Article 18.3.10, it shall notify the other Parties that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

ARTICLE 19. ASSIGNMENT

19.1 Assignment. This LGIA may be assigned by a Party only with the written consent of the other Parties; provided that a Party may assign this LGIA without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA; and provided further that the Interconnection Customer shall have the right to assign this LGIA, without the consent of the ISO or Participating TO, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that the Interconnection Customer will promptly notify the ISO and Participating TO of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the ISO and Participating TO of the date and particulars of any such exercise of assignment right(s), including providing the ISO and Participating TO with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this Article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

ARTICLE 20. SEVERABILITY

20.1 Severability. If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if the Interconnection Customer (or any third party, but only if such third party is not acting at the direction of the Participating TO or ISO) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of the provisions of Article 5.1.2 or 5.1.4 shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

ARTICLE 21. COMPARABILITY

21.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

ARTICLE 22. CONFIDENTIALITY

22.1 Confidentiality. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by any of the Parties to the other Parties prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Parties receiving the information that the information is confidential.

If requested by any Party, the other Parties shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party

may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 Term. During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of this LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Parties that it no longer is confidential.

22.1.3 Release of Confidential Information. No Party shall release or disclose Confidential Information to any other person, except to its employees, consultants, Affiliates (limited by the Standards of Conduct requirements set forth in Part 358 of FERC's Regulations, 18 C.F.R. 358), subcontractors, or to parties who may be or considering providing financing to or equity participation with the Interconnection Customer, or to potential purchasers or assignees of the Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 Rights. Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Parties. The disclosure by each Party to the other Parties of Confidential Information shall not be deemed a waiver by a Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 No Warranties. The mere fact that a Party has provided Confidential Information does not constitute a warranty or representation as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to the other Parties nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 Standard of Care. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Parties under this LGIA or its regulatory requirements.

22.1.7 Order of Disclosure. If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires any Party, by subpoena, oral

deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Parties with prompt notice of such request(s) or requirement(s) so that the other Parties may seek an appropriate protective order or waive compliance with the terms of this LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 Termination of Agreement. Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from another Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 Remedies. The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 Disclosure to FERC, its Staff, or a State. Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 C.F.R. section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties to this LGIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, Confidential Information shall not be disclosed by the other Parties to any person not employed or retained by the other Parties, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Parties, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or

ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Parties in writing of the information it claims is confidential. Prior to any disclosures of another Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

ARTICLE 23. ENVIRONMENTAL RELEASES

23.1 Each Party shall notify the other Parties, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Parties. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Parties copies of any publicly available reports filed with any Governmental Authorities addressing such events.

ARTICLE 24. INFORMATION REQUIREMENTS

24.1 **Information Acquisition**. The Participating TO and the Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 **Information Submission by Participating TO**. The initial information submission by the Participating TO shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include the Participating TO's Transmission System information necessary to allow the Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Participating TO and the Interconnection Customer. On a monthly basis the Participating TO shall provide the Interconnection Customer and the ISO a status report on the construction and installation of the Participating TO's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 **Updated Information Submission by Interconnection Customer**. The updated information submission by the Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. The Interconnection Customer shall submit a completed copy of the Electric Generating Unit data requirements contained in Part 1 to the LGIP. It shall also include any additional information provided to the Participating TO and the ISO for the Interconnection Studies. Information in this submission shall be the most current Electric Generating Unit design or expected performance data. Information submitted for stability models shall be compatible with the Participating TO and ISO standard models. If there is no compatible model, the Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Interconnection Customer's data is materially different from what was originally provided to the Participating TO and the ISO for the Interconnection Studies, then the Participating TO and the ISO will conduct appropriate studies pursuant to the LGIP to determine the impact on the

Participating TO's Transmission System and affected portions of the ISO Controlled Grid based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed and all other requirements of this LGIA are satisfied.

24.4 Information Supplementation. Prior to the Trial Operation date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Electric Generating Unit information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Electric Generating Unit as required by Good Utility Practice such as an open circuit "step voltage" test on the Electric Generating Unit to verify proper operation of the Electric Generating Unit's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Electric Generating Unit at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent (5 percent) change in Electric Generating Unit terminal voltage initiated by a change in the voltage regulators reference voltage. The Interconnection Customer shall provide validated test recordings showing the responses of Electric Generating Unit terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Electric Generating Unit's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Electric Generating Unit terminal or field voltages is provided. Electric Generating Unit testing shall be conducted and results provided to the Participating TO and the ISO for each individual Electric Generating Unit in a station.

Subsequent to the Commercial Operation Date, the Interconnection Customer shall provide the Participating TO and the ISO any information changes due to equipment replacement, repair, or adjustment. The Participating TO shall provide the Interconnection Customer any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Participating TO-owned substation that may affect the Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information pursuant to Article 5.19.

ARTICLE 25. INFORMATION ACCESS AND AUDIT RIGHTS

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is necessary in order for the other Party to: (i) verify the costs incurred by the disclosing Party for which the other Party is responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA. Nothing in this Article 25 shall obligate the ISO to make available to a Party any third party information in its possession or control if making such third party information available would violate an ISO Tariff restriction on the use or disclosure of such third party information.

25.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Parties when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this LGIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this LGIA, the Parties' audit rights shall include audits of a Party's costs pertaining to such Party's performance or satisfaction of obligations owed to the other Party under this LGIA, calculation of invoiced amounts, the ISO's efforts to allocate responsibility for the provision of reactive support to the ISO Controlled Grid, the ISO's efforts to allocate responsibility for interruption or reduction of generation on the ISO Controlled Grid, and each such Party's actions in an Emergency Condition.

25.3.1 The Interconnection Customer and the Participating TO shall each have the right, during normal business hours, and upon prior reasonable notice to the other Party, to audit at its own expense the other Party's accounts and records pertaining to either such Party's performance or either such Party's satisfaction of obligations owed to the other Party under this LGIA. Subject to Article 25.3.2, any audit authorized by this Article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each such Party's performance and satisfaction of obligations under this LGIA. Each such Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.3.2 Notwithstanding anything to the contrary in Article 25.3, each Party's rights to audit the ISO's accounts and records shall be as set forth in Article 12 of the ISO Tariff.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades constructed by the Participating TO shall be subject to audit for a period of twenty-four months following the Participating TO's issuance of a final invoice in accordance with Article 12.2. Accounts and records related to the design, engineering, procurement, and construction of Participating TO's Interconnection Facilities and/or Stand Alone Network Upgrades constructed by the Interconnection Customer shall be subject to audit and verification by the Participating TO and the ISO for a period of twenty-four months following the Interconnection Customer's issuance of a final invoice in accordance with Article 5.2(8).

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to a Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought; provided that each Party's rights to audit the ISO's accounts and records shall be as set forth in Article 12 of the ISO Tariff.

25.5 Audit Results. If an audit by the Interconnection Customer or the Participating TO determines that an overpayment or an underpayment has occurred with respect to the other Party, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination. The Party that is owed payment shall render an invoice to the other Party and such invoice shall be paid pursuant to Article 12 hereof.

25.5.1 Notwithstanding anything to the contrary in Article 25.5, the Interconnection Customer's and Participating TO's rights to audit the ISO's accounts and records shall be as set forth in Article 12 of the ISO Tariff, and the ISO's process for remedying an overpayment or underpayment shall be as set forth in the ISO Tariff.

ARTICLE 26. SUBCONTRACTORS

26.1 General. Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

26.2 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the ISO or Participating TO be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

ARTICLE 27. DISPUTES

All disputes arising out of or in connection with this LGIA whereby relief is sought by or from the ISO shall be settled in accordance with the provisions of Article 13 of the ISO Tariff, except that references to the ISO Tariff in such Article 13 of the ISO Tariff shall be read as references to this LGIA. Disputes arising out of or in connection with this LGIA not subject to provisions of Article 13 of the ISO Tariff shall be resolved as follows:

27.1 Submission. In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 External Arbitration Procedures. Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and

any applicable FERC regulations; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail.

27.3 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 Costs. Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

ARTICLE 28. REPRESENTATIONS, WARRANTIES AND COVENANTS

28.1 General. Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located**;** and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 Authority. Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 No Conflict. The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

ARTICLE 29. [RESERVED]

ARTICLE 30. MISCELLANEOUS

30.1 Binding Effect. This LGIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts. In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation. This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix to this LGIA, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 Entire Agreement. This LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement among the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between or among the Parties with respect to the subject matter of this LGIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this LGIA.

30.5 No Third Party Beneficiaries. This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 Waiver. The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this LGIA. Termination or Default of this LGIA for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 Headings. The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 Multiple Counterparts. This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment. The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by all of the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by all of the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. The ISO and Participating TO shall each have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

> Recitals, 1, 2.1, 2.2, 2.3, 2.4, 2.6, 3.1, 3.3, 4.1, 4.2, 4.4, 4.5, 5 preamble, 5.4, 5.7, 5.8, 5.9, 5.12, 5.13, 5.18, 5.19.1, 7.1, 7.2, 8, 9.1, 9.2, 9.3, 9.5, 9.6, 9.7, 9.8, 9.10, 10.3, 11.4, 12.1, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24.3, 24.4, 25.1, 25.2, 25.3 (excluding subparts), 25.4.2, 26, 28, 29, 30, Part D, Part F, Part G, and any other Article not reserved exclusively to the Participating TO or the ISO below.

The Participating TO shall have the exclusive right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

> 2.5, 5.1, 5.2, 5.3, 5.5, 5.6, 5.10, 5.11, 5.14, 5.15, 5.16, 5.17, 5.19 (excluding 5.19.1), 6, 7.3, 9.4, 9.9, 10.1, 10.2, 10.4, 10.5, 11.1, 11.2, 11.3, 11.5, 12.2, 12.3, 12.4, 24.1, 24.2, 25.3.1, 25.4.1, 25.5 (excluding 25.5.1), 27 (excluding preamble), Part A, Part B, Part C, and Part E.

The ISO shall have the exclusive right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

> 3.2, 4.3, 4.6, 11.6, 25.3.2, 25.5.1, and 27 preamble.

The Interconnection Customer, the ISO, and the Participating TO shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership among the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

30.13 Joint and Several Obligations. Except as otherwise provided in this LGIA, the obligations of the ISO, the Participating TO, and the Interconnection Customer are several, and are neither joint nor joint and several.

IN WITNESS WHEREOF, the Parties have executed this LGIA in multiple originals, each of which shall constitute and be an original effective agreement among the Parties.

By: _____

Title: _____

Date:

California Independent System Operator Corporation

By: _____

Title: _____

Date:

By: _____

Title: _____

Date:

Appendices to LGIA

Part A Interconnection Facilities, Network Upgrades and Distribution Upgrades

Part B Milestones

Part C Interconnection Details

Part D Security Arrangements Details

Part E Commercial Operation Date

Part F Addresses for Delivery of Notices and Billings

Part G Reliability Management System Agreement

Part H Interconnection Requirements for a Wind Generating Plant

Part A
To LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. Interconnection Facilities:

(a) [insert Interconnection Customer's Interconnection Facilities]:

(b) [insert Participating TO's Interconnection Facilities]:

2. Network Upgrades:

(a) [insert Stand Alone Network Upgrades]:

(b) [insert Other Network Upgrades]:

(i) [insert Participating TO's Reliability Network Upgrades]

(ii) [insert Participating TO's Delivery Network Upgrades]

3. Distribution Upgrades:

Part B
To LGIA

Milestones

Part C
To LGIA

Interconnection Details

Part D
To LGIA

Security Arrangements Details

Infrastructure security of ISO Controlled Grid equipment and operations and control hardware and software is essential to ensure day-to-day ISO Controlled Grid reliability and operational security. FERC will expect the ISO, all Participating TOs, market participants, and Interconnection Customers interconnected to the ISO Controlled Grid to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

The Interconnection Customer shall meet the requirements for security implemented pursuant to the ISO Tariff, including the ISO's standards for information security posted on the ISO's internet web site at the following internet address: http://www.caiso.com/pubinfo/info-security/index.html.

Part E
To LGIA

Commercial Operation Date

This Part E is a part of the LGIA.

[Date]

[ISO Address]

[Participating TO Address]

Re: _____ Electric Generating Unit

Dear _____:

On **[Date] [Interconnection Customer]** has completed Trial Operation of Unit No. ___. This letter confirms that [Interconnection Customer] commenced Commercial Operation of Unit No. ___ at the Electric Generating Unit, effective as of **[Date plus one day]**.

Thank you.

[Signature]

[Interconnection Customer Representative]

Part F
To LGIA

Addresses for Delivery of Notices and Billings

Notices:.

ISO:

[To be supplied.]

Participating TO:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

Billings and Payments:

Participating TO:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

ISO:

[To be supplied.]

Alternative Forms of Delivery of Notices (telephone, facsimile or e-mail):

ISO:

[To be supplied.]

Participating TO:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

Part G
To LGIA

Reliability Management System Agreement

RELIABILITY MANAGEMENT SYSTEM AGREEMENT
by and between
[TRANSMISSION OPERATOR]
and
[GENERATOR]

THIS RELIABILITY MANAGEMENT SYSTEM AGREEMENT (the "Agreement"), is entered into this ____ day of _____, 2002, by and between _____ (the "Transmission Operator") and _____ (the "Generator").

WHEREAS, there is a need to maintain the reliability of the interconnected electric systems encompassed by the WSCC in a restructured and competitive electric utility industry;

WHEREAS, with the transition of the electric industry to a more competitive structure, it is desirable to have a uniform set of electric system operating rules within the Western Interconnection, applicable in a fair, comparable and non-discriminatory manner, with which all market participants comply; and

WHEREAS, the members of the WSCC, including the Transmission Operator, have determined that a contractual Reliability Management System provides a reasonable, currently available means of maintaining such reliability.

NOW, THEREFORE, in consideration of the mutual agreements contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Transmission Operator and the Generator agree as follows:

1. PURPOSE OF AGREEMENT

The purpose of this Agreement is to maintain the reliable operation of the Western Interconnection through the Generator's commitment to comply with certain reliability standards.

2. DEFINITIONS

In addition to terms defined in the beginning of this Agreement and in the Recitals hereto, for purposes of this Agreement the following terms shall have the meanings set forth beside them below.

Control Area means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Western Interconnection.

FERC means the Federal Energy Regulatory Commission or a successor agency.

Member means any party to the WSCC Agreement.

Party means either the Generator or the Transmission Operator and

Parties means both of the Generator and the Transmission Operator.

Reliability Management System or **RMS** means the contractual reliability management program implemented through the WSCC Reliability Criteria Agreement, the WSCC RMS Agreement, this Agreement, and any similar contractual arrangement.

Western Interconnection means the area comprising those states and provinces, or portions thereof, in Western Canada, Northern Mexico and the Western United States in which Members of the WSCC operate synchronously connected transmission systems.

Working Day means Monday through Friday except for recognized legal holidays in the state in which any notice is received pursuant to Section 8.

WSCC means the Western Systems Coordinating Council or a successor entity.

WSCC Agreement means the Western Systems Coordinating Council Agreement dated March 20, 1967, as such may be amended from time to time.

WSCC Reliability Criteria Agreement means 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.

WSCC RMS Agreement means an agreement between the WSCC and the Transmission Operator requiring the Transmission Operator to comply with the reliability criteria contained in the WSCC Reliability Criteria Agreement.

WSCC Staff means those employees of the WSCC, including personnel hired by the WSCC on a contract basis, designated as responsible for the administration of the RMS.

3. TERM AND TERMINATION

3.1 Term. This Agreement shall become effective [thirty (30) days after the date of issuance of a final FERC order accepting this Agreement for filing without requiring any changes to this Agreement unacceptable to either Party. Required changes to this Agreement shall be deemed unacceptable to a Party only if that Party provides notice to the other Party within fifteen (15) days of issuance of the applicable FERC order that such order is unacceptable].
[Note: if the interconnection agreement is not FERC jurisdictional, replace bracketed language with: [on the later of: (a) the date of execution; or (b) the effective date of the WSCC RMS Agreement.]]

3.2 Notice of Termination of WSCC RMS Agreement. The Transmission Operator shall give the Generator notice of any notice of termination of the WSCC RMS Agreement by the WSCC or by the Transmission Operator within fifteen (15) days of receipt by the WSCC or the Transmission Operator of such notice of termination.

3.3 Termination by the Generator. The Generator may terminate this Agreement as follows:
(a) following the termination of the WSCC RMS Agreement for any reason by the WSCC or by the Transmission Operator, provided such notice is provided within forty-five (45) days of the termination of the WSCC RMS Agreement;
(b) following the effective date of an amendment to the requirements of the WSCC Reliability Criteria Agreement that adversely affects the Generator, provided notice of such termination is given within forty-five (45) days of the date of issuance of a FERC order accepting such amendment for filing, provided further that the forty-five (45) day period within which notice of termination is required may be extended by the Generator for an additional forty-five (45) days if the Generator gives written notice to the Transmission Operator of such requested extension within the initial forty-five (45) day period; or
(c) for any reason on one year's written notice to the Transmission Operator and the WSCC.

3.4 Termination by the Transmission Operator. The Transmission Operator may terminate this Agreement on thirty (30) days' written notice following the termination of the WSCC RMS Agreement for any reason by the WSCC or by the Transmission Operator, provided such notice is provided within thirty (30) days of the termination of the WSCC RMS Agreement.

3.5 Mutual Agreement. This Agreement may be terminated at any time by the mutual agreement of the Transmission Operator and the Generator.

4. COMPLIANCE WITH AND AMENDMENT OF WSCC RELIABILITY CRITERIA

4.1 Compliance with Reliability Criteria. The Generator agrees to comply with the requirements of the WSCC Reliability Criteria Agreement, including the applicable WSCC reliability criteria contained in Section IV of Annex A thereof, and, in the event of failure to comply, agrees to be subject to the sanctions applicable to such failure. Each and all of the provisions of the WSCC Reliability Criteria Agreement are hereby incorporated by reference into this Agreement as though set forth fully herein, and the Generator shall for all purposes be considered a Participant, and shall be entitled to all of the rights and privileges and be subject to all of the obligations of a Participant, under and in connection with the WSCC Reliability Criteria Agreement, including but not limited to the rights, privileges and obligations set forth in Sections 5, 6 and 10 of the WSCC Reliability Criteria Agreement.

4.2 Modifications to WSCC Reliability Criteria Agreement. The Transmission Operator shall notify the Generator within fifteen (15) days of the receipt of notice from the WSCC of the initiation of any WSCC process to modify the WSCC Reliability Criteria Agreement. The WSCC RMS Agreement specifies that such process shall comply with the procedures, rules, and regulations then applicable to the WSCC for modifications to reliability criteria.

4.3 Notice of Modifications to WSCC Reliability Criteria Agreement. If, following the process specified in Section 4.2, any modification to the WSCC Reliability Criteria Agreement is to take effect, the Transmission Operator shall provide notice to the Generator at least forty-five (45) days before such modification is scheduled to take effect.

4.4 Effective Date. Any modification to the WSCC Reliability Criteria Agreement shall take effect on the date specified by FERC in an order accepting such modification for filing.

4.5 Transfer of Control or Sale of Generation Facilities. In any sale or transfer of control of any generation facilities subject to this Agreement, the Generator shall as a condition of such sale or transfer require the acquiring party or transferee with respect to the transferred facilities either to assume the obligations of the Generator with respect to this Agreement or to enter into an agreement with the Control Area Operator in substantially the form of this Agreement.

5. SANCTIONS

5.1 Payment of Monetary Sanctions. The Generator shall be responsible for payment directly to the WSCC of any monetary sanction assessed against the Generator pursuant to this Agreement and the WSCC Reliability Criteria Agreement. Any such payment shall be made pursuant to the procedures specified in the WSCC Reliability Criteria Agreement.

5.2 Publication. The Generator consents to the release by the WSCC of information related to the Generator's compliance with this Agreement only in accordance with the WSCC Reliability Criteria Agreement.

5.3 Reserved Rights. Nothing in the RMS or the WSCC Reliability Criteria Agreement shall affect the right of the Transmission Operator, subject to any necessary regulatory approval, to take such other measures to maintain reliability, including disconnection, which the Transmission Operator may otherwise be entitled to take.

6. THIRD PARTIES

Except for the rights and obligations between the WSCC and Generator specified in Sections 4 and 5, this Agreement creates contractual rights and obligations solely between the Parties. Nothing in this Agreement shall create, as between the Parties or with respect to the WSCC: (1) any obligation or liability whatsoever (other than as expressly provided in this Agreement), or (2) any duty or standard of care whatsoever. In addition, nothing in this Agreement shall create any duty, liability, or standard of care whatsoever as to any other party. Except for the rights, as a third-party beneficiary with respect to Sections 4 and 5, of the WSCC against Generator, no third party shall have any rights whatsoever with respect to enforcement of any provision of this Agreement. Transmission Operator and Generator expressly intend that the WSCC is a third-party beneficiary to this Agreement, and the WSCC shall have the right to seek to enforce against Generator any provisions of Sections 4 and 5, provided that specific performance shall be the sole remedy available to the WSCC pursuant to this Agreement, and Generator shall not be liable to the WSCC pursuant to this Agreement for damages of any kind whatsoever (other than the payment of sanctions to the WSCC, if so construed), whether direct, compensatory, special, indirect, consequential, or punitive.

7. REGULATORY APPROVALS

This Agreement shall be filed with FERC by the Transmission Operator under Section 205 of the Federal Power Act. In such filing, the Transmission Operator shall request that FERC accept this Agreement for filing without modification to become effective on the day after the date of a FERC order accepting this Agreement for filing. [This section shall be omitted for agreements not subject to FERC jurisdiction.]

8. NOTICES

Any notice, demand or request required or authorized by this Agreement to be given in writing to a Party shall be delivered by hand, courier or overnight delivery service, mailed by certified mail (return receipt requested) postage prepaid, faxed, or delivered by mutually agreed electronic means to such Party at the following address:

_____: _____
_____
_____
_____
Fax: _____

_____: _____
_____
_____
_____
Fax: _____

The designation of such person and/or address may be changed at any time by either Party upon receipt by the other of written notice. Such a notice served by mail shall be effective upon receipt. Notice transmitted by facsimile shall be effective upon receipt if received prior to 5:00 p.m. on a Working Day, and if not received prior to 5:00 p.m. on a Working Day, receipt shall be effective on the next Working Day.

9. APPLICABILITY

This Agreement (including all appendices hereto and, by reference, the WSCC Reliability Criteria Agreement) constitutes the entire understanding between the Parties hereto with respect to the subject matter hereof, supersedes any and all previous understandings between the Parties with respect to the subject matter hereof, and binds and inures to the benefit of the Parties and their successors.

10. AMENDMENT

No amendment of all or any part of this Agreement shall be valid unless it is reduced to writing and signed by both Parties hereto. The terms and conditions herein specified shall remain in effect throughout the term and shall not be subject to change through application to the FERC or other governmental body or authority, absent the agreement of the Parties.

11. INTERPRETATION

Interpretation and performance of this Agreement shall be in accordance with, and shall be controlled by, the laws of the State of _____ but without giving effect to the provisions thereof relating to conflicts of law. Article and section headings are for convenience only and shall not affect the interpretation of this Agreement. References to articles, sections and appendices are, unless the context otherwise requires, references to articles, sections and appendices of this Agreement.

12. PROHIBITION ON ASSIGNMENT

This Agreement may not be assigned by either Party without the consent of the other Party, which consent shall not be unreasonably withheld; provided that the Generator may without the consent of the WSCC assign the obligations of the Generator pursuant to this Agreement to a transferee with respect to any obligations assumed by the transferee by virtue of Section 4.5 of this Agreement.

13. SEVERABILITY

If one or more provisions herein shall be invalid, illegal or unenforceable in any respect, it shall be given effect to the extent permitted by applicable law, and such invalidity, illegality or unenforceability shall not affect the validity of the other provisions of this Agreement.

14. COUNTERPARTS

This Agreement may be executed in counterparts and each shall have the same force and effect as an original.

IN WITNESS WHEREOF, the Transmission Operator and the Generator have each caused this Reliability Management System Agreement to be executed by their respective duly authorized officers as of the date first above written.

_____

By: _____
Name:
Title:

_____

By: _____
Name:
Title:

Part H
To LGIA

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Part H sets forth requirements and provisions specific to a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with FERC, filed with FERC in unexecuted form, or filed with FERC as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the Participating TO. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or “GSU”), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.
2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Part H LVRT Standard are exempt from meeting the Part H LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Part H LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the Participating TO. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the ISO Controlled Grid. A wind generating plant shall remain interconnected during such a fault on the ISO Controlled Grid for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.
2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the ISO Controlled Grid at the same location at the effective date of the Part H LVRT Standard are exempt from meeting the Part H LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Part H LVRT Standard.

ii. Power Factor Design Criteria (Reactive Power)

A wind generating plant shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA in order to maintain a specified voltage schedule, if the Interconnection System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two, if agreed to by the Participating TO and ISO. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Interconnection System Impact Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Participating TO and ISO to protect system reliability. The Participating TO and ISO and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

ISO TARIFF APPENDIX W

Interconnection Procedures in Effect Prior to July 1, 2005 ("Amendment 39 Procedures")

ISO TARIFF APPENDIX Z

Credit Policy and Procedures Guide

REVISION HISTORY

Revision No.	Date	Description
1.0	4/4/2003	Original Draft
2.0	8/13/2004	Second major revision – updated to include only the current credit policies and procedures.
3.0	5/6/2005	Third major revision – updated to include proposed credit policy changes.
4.0	3/6/2006	Fourth major revision – major restructuring and updating to support the new credit policy. Changes the method for determining a Market Participant's or FTR Bidder's unsecured credit limit from simply having an approved credit rating with one that bases unsecured credit as a percentage of Tangible Net Worth or Net Assets based on the type of entity and other quantitative and qualitative factors.
4.1	6/26/2006	Revision made to reflect necessary updates to the CPPG, in accordance with FERC's Notice of Extension of Time issued June 2, 2006, in Docket No. ER06-700-000. Revision to satisfy FERC Order Conditionally Accepting Tariff Revisions Governing Credit Policy issued May 12, 2006 115 FERC ¶ 61,170. Modifications included: • Deletion of Section A-1 describing the transition from the old "Approved Credit Rating Approach" and renumbering of the sections in Part A due to the passing of the transition period; • The addition of Unsecured Credit Limit calculation examples for Unrated Public/Private Corporations, Rated Governmental Entities and Unrated Governmental Entities; • Deletion of the reference to the ISO Board of Governor's ability to reduce the $250M cap on Unsecured Credit Limits; • Description of an alternative Estimated Aggregate Liability calculation method in Section C-2, Section C-3, Section C-3.1 and Appendix 1A.

TABLE OF CONTENTS

INTRODUCTION

All Market Participants and FTR Bidders requesting transmission services with the ISO will be subject to a financial review in accordance with the ISO standards for determining creditworthiness. Such review procedures are designed to protect Market Participants and FTR Bidders from undue exposure to default risk by other Market Participants and FTR Bidders.

This Credit Policy & Procedures Guide (CPPG) provides Market Participants and FTR Bidders further detailed information regarding credit-related provisions described in Section 12 of the ISO Tariff. By providing this information, the ISO hopes to provide Market Participants and FTR Bidders increased visibility into the standard, commercial credit review procedures that the ISO uses in evaluating a Market Participant's and FTR Bidder's ability to meet its financial obligations. Specifically, Market Participants and FTR Bidders will find in the CPPG:

- Information on the processes used to administer the credit policy;
- The methodology used to calculate Unsecured Credit Limits and Estimated Aggregate Liabilities;
- Acceptable forms of Financial Security and the associated processes for requesting, posting and administering Financial Security;
- Security requirements for FTR Bidders;
- Consequences for Market Participants' failure to meet their credit related obligations; and
- Other credit-related information.

Principles

The ISO's intent is to maintain the confidence of Market Participants and FTR Bidders in the ISO markets and to sustain the ISO's mission of ensuring an adequate supply of power at a reasonable cost, by equitably, consistently and strictly enforcing these credit procedures.

The ISO recognizes the importance to Market Participants and FTR Bidders that credit-related practices be transparent and comprehensive. The ISO will endeavor to maintain an accurate procedures guide that describes the methods used to conduct its credit analysis as well as other credit-related practices and administrative procedures on the ISO's Home Page.

Definitions

Any term defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Guide. In any instances where a definition in this document conflicts with a definition in the ISO Tariff, the ISO Tariff definition will prevail. Section number references refer to sections of the CPPG unless specifically stated otherwise.

The following table defines terms used throughout this document and their associated meanings:

TERM	DEFINITION
Affiliated Entities	Legally distinct business units that are Affiliates, as defined in the ISO Tariff.
Aggregate Credit Limit (ACL)	The sum of a Market Participant's or FTR Bidder's Unsecured Credit Limit and its Financial Security Amount, as provided for in Section 12 of the ISO Tariff.
Average Rating Default Probability (ARDP)	The sum of Credit Rating Default Probabilities divided by the total number of Credit Rating Default Probabilities used.
Business Association Identification Number (BAID)	An identification code used by the ISO to represent a Market Participant or a FTR Bidder. A Market Participant may have more than one BAID.
Credit Rating Default Probability	The 5 Year Median Default Probability based on a rating agency's credit rating as listed in the Credit Rating Default Probability table in Section A-2.2 of this CPPG.
FTR Bidder	An entity that submits a bis in an FTR auction conducted by the ISO in accordance with Section 36.4 of the ISO Tariff.
Collateral	See Financial Security.
Combined Default Probability (CDP)	A Market Participant's or FTR Bidder's blended probability of default based on credit agencies' Average Rating Default Probability and MKMV Default Probability according to rules established for different entity types.
Estimated Aggregate Liability (EAL)	The sum of a Market Participant's or FTR Bidder's known and reasonably estimated potential liabilities for a specified time period arising from charges described in the ISO Tariff, as provided for in Section 12 of the ISO Tariff.
Financial Security	Any of the types of financial instruments listed in Section 12 of the ISO Tariff that are posted by a Market Participant or FTR Bidder.
Financial Security Amount	The level of Financial Security posted in accordance with Section 12 of the ISO Tariff by a Market Participant or FTR Bidder.
Material Change in Financial Condition	A change in or potential threat to the financial condition of a Market Participant that increases the risk that the Market Participant will be unlikely to meet some or all of its financial obligations. The types of Material Change in Financial Condition include but are not limited to the following: (a) A credit agency downgrade; (b) Being placed on a credit watch list by a major rating agency; (c) A bankruptcy filing; (d) Insolvency; (e) The filing of a material lawsuit that could significantly adversely affect past, current or future financial results; or any change in the financial condition of the Market Participant which exceeds a five percent (5%) reduction in

	the Market Participant's tangible net worth for the Market Participant's preceding fiscal year, calculated in accordance with generally accepted accounting practices.
MKMV Default Probability	The Moody's KMV default probability determined in accordance with step 3 of Section A-2.2 of this CPPG.
Nationally Recognized Statistical Rating Organizations (NRSRO)	National credit rating agencies as designated by the U.S. Securities & Exchange Commission.
Net Assets (NA)	For governmental or not-for-profit entities, defined as total assets less total liabilities.
Rated Governmental Entity	A municipal utility or state or federal agency that holds an issuer, counterparty or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Rated Public/Private Corporation	An investor owned or privately held entity that holds an issuer, counterparty or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Scheduling Coordinator	An entity certified by the ISO for the purposes of undertaking the functions specified in Section 4.5.3 of the ISO Tariff.
Scheduling Coordinator Identification Number (SCID)	A unique number assigned to each Scheduling Coordinator by the ISO.
Tangible Net Worth (TNW)	Total Assets minus Intangibles (e.g., Good Will) minus Total Liabilities.
Unrated Governmental Entity	A municipal utility or state or federal agency that does not hold an issuer, counterparty or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Unrated Public/Private Corporation	An investor owned or privately held entity that does not hold an issuer, counterparty or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Unsecured Credit Limit (UCL)	The level of credit established for a Market Participant or a FTR Bidder that is not secured by any form of Financial Security, as provided for in Section 12 of the ISO Tariff.

Rules of Interpretation

Unless the context otherwise requires, if the provisions of this Guide and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Guide only to aid understanding.

A reference in this Guide to a given agreement, the ISO Guide or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

The captions and headings in this Guide are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

A reference to a day or Trading Day is to a calendar day unless otherwise specified.

PART A: UNSECURED CREDIT

A-1. Credit Assessment Requirements

As provided in Section 12.1.1 of the ISO Tariff, an approved Application for Unsecured Credit must be on file with the ISO for those Market Participants and FTR Bidders seeking an Unsecured Credit Limit. A copy of the Application for Unsecured Credit can be found at the ISO Home Page. An Application for Unsecured Credit must only be filed once by a Market Participant or FTR Bidder. A Market Participant or FTR Bidder should subsequently inform the ISO of changes to contact or other relevant information contained in the Application.

As provided in Section 12.1 of the ISO Tariff, each Market Participant or FTR Bidder must secure its financial transactions with the ISO by maintaining an Unsecured Credit Limit (UCL) and/or by posting Financial Security. The combination of the UCL and the Financial Security Amount represents the Market Participant's or FTR Bidder's Aggregate Credit Limit (ACL). The ISO will periodically estimate a Market Participant's liabilities and will notify it in case its ACL needs to be increased through posting of additional Financial Security. It is the Market Participant's responsibility to maintain a sufficient ACL to meet all of their estimated financial obligations.

As provided in Sections 12.1.1, 12.1.5 and 12.4 of the ISO Tariff, each Market Participant and FTR Bidder requesting or having unsecured credit is required to submit to the ISO or its agent financial statements and other information related to the overall financial health of the Market Participant or FTR Bidder that will be used in determining the Market Participant's or and FTR Bidder's creditworthiness and ability to meet its financial obligations. Market Participants and FTR Bidders are responsible for the timely submission of their latest financial statements either directly or by indicating where the material can be located on their company website and/or on the U.S. Security Exchange Commission's website as well as other information that may be reasonably necessary for the ISO to conduct its evaluation. The ISO may also rely on financial reporting agencies and the financial press as part of the credit evaluation process.

As provided in Sections 12.1.1 and 12.1.2 of the ISO Tariff, as a result of the credit evaluation, a Market Participant or FTR Bidder may be denied an Unsecured Credit Limit with the ISO. Market Participants or FTR Bidders who have been denied an Unsecured Credit Limit may submit other forms of Financial Security acceptable to the ISO (see Part B) sufficient to cover their Estimated Aggregate Liabilities.

A-1.1. Financial Statements

As provided in Section 12.1.1 of the ISO Tariff, Market Participants and FTR Bidders requesting unsecured credit are required to provide financial statements so that a credit review can be completed.

Based on availability, the Market Participant or FTR Bidder must submit a financial statement for the most recent financial quarter, as well as audited financial statements for the most recent three fiscal years, or the period of existence of the Market Participant or FTR Bidder, if shorter, to the ISO or the ISO's designee. If audited financial statements are not available, financial statements, as described below, should be submitted, signed and attested to by an officer of the Market Participant or FTR Bidder as a fair representation of the financial condition of the Market Participant or FTR Bidder in accordance with generally accepted accounting principles.

The information should include, but is not limited to, the following:

a. If publicly traded:

i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively

ii. Form 8-K reports, if any

b. If privately held or governmentally owned:

i. Management's Discussion & Analysis (if available)

ii. Report of Independent Accountants (if available)

iii. Financial Statements, including:

- Balance Sheet
- Income Statement
- Statement of Cash Flows
- Statement of Stockholder's Equity

iv. Notes to Financial Statements

If the above information is available electronically on the Internet, the Market Participant or FTR Bidder may indicate in written or electronic communication where such statements are located for retrieval by the ISO or the ISO's designee.

A-1.2. Rating Agency Reports

Rating agency reports and credit ratings are utilized from those entities designated by the U.S. Securities & Exchange Commission - http://www.sec.gov/answers/nrsro.htm. The ratings utilized are to be long-term credit ratings for the entity as a whole, on a stand-alone basis without the benefit of third party credit support (also known as "issuer" or "underlying" ratings). Project financing ratings or insured bond ratings do not qualify, since such credit ratings are based on the availability of revenue streams or third-party funding available to bond holders but not necessarily available to trade creditors such as the suppliers to the ISO markets. Moreover, the ISO has been advised by the credit rating agencies that these projects or insured bond ratings cannot be considered as valid measures of an entity's ability to meet its non-bond obligations.

If a Market Participant or FTR Bidder has only a "senior long-term unsecured rating" instead of an issuer rating, the rating will be deemed acceptable; however, for the Unsecured Credit Limit calculation, the rating will be lowered by one rating level to account for the risk of obligations to the ISO having a lower claim priority.

If a Market Participant or FTR Bidder has only a "short-term rating" instead of an issuer rating, the ISO will utilize an equivalent long-term rating based on the highlighted rating in the following long- and short-term rating correlation table:

S&P		**Moody's**	
Short Term Rating	Equivalent Long Term Ratings	Short Term Rating	Equivalent Long Term Ratings
A-1+	AAA/AA+/**AA**/AA-/A+	P1	Aaa/Aa1/Aa2/**AA3**/A1/A2/A3
A-1	A+/**A**/A-	P2	A3/Baa1/**Baa2**/Baa3
A-2	A-/**BBB+**/BBB	P3	Baa3/Ba1/**Ba2**/Ba3
A-3	BBB/**BBB-**	NP	B1/B2/B3/Caa1/**Caa2**/ Caa3/Ca/C
B	BB+/**BB**/BB-		
C	B+ / B / B- / CCC+ / **CCC** / CCC- / CC / C		
D	**D**		

The highlighted rating represents a mid-range rating in the rating agencies' long- and short-term rating correlation table. Equivalent ratings from other rating agencies may also be considered. If the short-term rating is noted as being under a credit watch with negative implications, the ISO will use the lowest long-term equivalent rating in the range for its assessment.

Rating agency reports, particularly credit ratings, are reviewed and updated minimally on a quarterly basis for those Market Participants with an Unsecured Credit Limit. They are also reviewed as needed if questions arise as to changes to a Market Participant's financial health and/or credit standing. Additionally, credit rating agency reports of downgrade/upgrades are reviewed upon notice from a rating agency to determine if the Unsecured Credit Limit should be correspondingly decreased/increased.

A-1.3. Other Qualitative and Quantitative Credit Strength Indicators

As provided in Section 12.1.1 of the ISO Tariff, the ISO may rely on information gathered from financial reporting agencies, the general/financial/energy press, and provided by the Market Participant or FTR Bidder to assess an entity's overall financial health and its ability to meet its financial obligations. Information considered by the ISO in this process may include the qualitative factors noted in FERC's Policy Statement on Electric Creditworthiness[3]:

a) Applicant's history;
b) Nature of organization and operating environment;
c) Management;
d) Contractual obligations;

[3] "*Policy Statement on Credit Related Issues for Electric OATT Transmission Providers, Independent System Operators and Regional Transmission Organizations*" (*Order E-40, Docket PL05-3-000, November 19, 2004), at footnote 13.*

e) Governance policies;
f) Financial and accounting policies;
g) Risk management and credit policies;
h) Market risk including price exposures, credit exposures and operational exposures;
i) Event risk; and
j) The state or local regulatory environment.

Material negative information in these areas may result in a reduction of up to 100% in the Unsecured Credit Limit that would otherwise be granted based on the methodology described in Section A-2.2. A Market Participant or FTR Bidder, upon request, will be provided a written analysis as to how the provisions of Section A-2.2 were applied in setting its Unsecured Credit Limit.

Notwithstanding the considerations described above, Market Participants and FTR Bidders are obligated to provide the ISO timely information regarding any Material Change in Financial Condition, i.e., an adverse change that could affect its or one of its affiliated entities ability to pay its debt or meet its Financial Security obligations as they become due. Examples of Material Changes in Financial Condition may include but are not limited to:

a) Credit agency downgrades;
b) Being placed on a credit watch list by a major rating agency;
c) A bankruptcy filing;
d) Insolvency;
e) The filing of a material lawsuit that could significantly and adversely affect past, current or future financial results; or
f) Any change in the financial condition of the Market Participant or FTR Bidder that exceeds a five percent (5%) reduction in the Market Participant's or FTR Bidder's Tangible Net Worth or Net Assets for the Market Participant's or FTR Bidder's preceding fiscal year, calculated in accordance with generally accepted accounting practices.

A-2. Unsecured Credit Limit Calculation

See Section 12.1.1A, 12.1.1A.1, 12.1.1A.2 and 12.1.1A.3 of the ISO Tariff.

A-3. Unsecured Credit Limit Issues for Affiliated Entities

As provided in Section 12.1.1.1 of the ISO Tariff, if any Market Participant or FTR Bidder requesting or maintaining an Unsecured Credit Limit is affiliated with one or more other entities subject to the credit requirements of Section 12 of the ISO Tariff, the ISO may consider the overall creditworthiness and financial condition of such Affiliates when determining the applicable Unsecured Credit Limit. The ISO may determine that the maximum Unsecured Credit Limit calculated in accordance with Section A-2 of this document applies to the combined activity of such Affiliates.

A-4. Unsecured Credit Limit for a Local Publicly Owned Electric Utility

A Local Publicly Owned Electric Utility with a governing body having ratemaking authority that has submitted an application for an Unsecured Credit Limit shall be entitled to an Unsecured Credit Limit of one million dollars ($1,000,000) without regard to its Net Assets. Such Local Publicly Owned Electric Utility shall be entitled to request an Unsecured Credit Limit based on Net Assets as provided in Section 12.1.1 of the ISO Tariff in order to establish an Unsecured Credit Limit as the greater of one million dollars ($1,000,000) or the amount determined as provided in Section 12.1.1 of the ISO Tariff. A public entity that is not a Local Publicly Owned Electric Utility is not entitled to an Unsecured Credit Limit of one million dollars ($1,000,000) under this Section but may seek to establish an Unsecured Credit Limit as provided in Section 12.1.1 of the ISO

Tariff or any other provision of the ISO Tariff that may apply.

Public entities, including Local Publicly Owned Electric Utilities, that operate through a Joint Powers Agreement, or a similar agreement acceptable to the ISO with the same legal force and effect, shall be entitled to aggregate or assign their Unsecured Credit Limits subject to the following limitations and requirements. A public entity that is a party to a Joint Powers Agreement or similar agreement and that is also participating independently in the ISO's markets with an established Unsecured Credit Limit shall not be entitled to assign or aggregate any portion of its Unsecured Credit Limit that the public entity is using to support financial liabilities associated with its individual participation in the ISO's markets. A Local Publicly Owned Electric Utility that operates through a Joint Powers Agreement or similar agreement that desires to aggregate a portion of its Unsecured Credit Limit that is equal to or less than one million dollars ($1,000,000) with one or more other Local Publicly Owned Electric Utilities that operate through that Joint Powers Agreement or similar agreement or to assign a portion of its Unsecured Credit Limit that is equal to or less than one million dollars ($1,000,000) to the Joint Powers Authority shall be entitled to do so. A Local Publicly Owned Electric Utility that operates through a Joint Powers Agreement or similar agreement that desires to aggregate its Unsecured Credit Limit with one or more other Local Publicly Owned Electric Utilities that operate through that Joint Powers Agreement or similar agreement or to assign a portion of its Unsecured Credit Limit to the Joint Powers Authority that exceeds one million dollars ($1,000,000), and any public entity that is not a Local Publicly Owned Electric Utility that operates through a Joint Powers Agreement or similar agreement that desires to aggregate its Unsecured Credit Limit with one or more other Local Publicly Owned Electric Utilities that operate through that Joint Powers Agreement or similar agreement or to assign any portion of its Unsecured Credit Limit to the Joint Powers Authority, shall provide documentation that is acceptable to the ISO and that demonstrates the Local Publicly Owned Electric Utility or public entity will assume responsibility for the financial liabilities of the Joint Powers Agency associated with the assigned or aggregated portion of the Unsecured Credit Limit. Such documentation may include a guaranty or similar instrument acceptable to the ISO.

Unsecured Credit Limits established through this section or through Section 12.1.1 of the ISO Tariff shall be subject to the ISO's consideration of the same qualitative factors that apply to all other Market Participants and FTR Bidders as set forth in Section A-1.3 of the ISO Credit Policy & Procedures Guide, Appendix Z to the ISO Tariff, and accordingly, the ISO may adjust their Unsecured Credit Limits pursuant to Section 12.1.1 of the ISO Tariff.

A. 5 Unsecured Credit Limit for an Unrated Governmental Entity that Receives Appropriations from the Federal Government or a State Government

An Unrated Governmental Entity that receives appropriations from the federal government or a state government that has submitted an application for an Unsecured Credit Limit shall be entitled to an Unsecured Credit Limit of the lower of the cap of 250 million dollars ($250,000,000) or the amount appropriated by the federal or relevant state government for the purpose of procuring energy and energy-related products and services for the applicable fiscal year. The Unrated Governmental Entity seeking to establish an Unsecured Credit Limit pursuant to this section shall provide documentation establishing its annual appropriations. Unsecured Credit Limits established pursuant to this section or through Section 12.1.1 of the ISO Tariff shall be subject to the ISO's consideration of the same qualitative factors that apply to all other Market Participants and FTR Bidders as set forth in Section A-1.3 of the ISO Credit Policy & Procedures Guide, Appendix Z to the ISO Tariff, and accordingly, the ISO may adjust their Unsecured Credit Limits pursuant to Section 12.1.1 of the ISO Tariff.

PART B: APPROVED FORMS FINANCIAL SECURITY

In accordance with Section 12.1.2 of the ISO Tariff, a Market Participant or FTR Bidder, at its own expense, may submit one or more of the following forms of Financial Security to meet its posting requirement (pro-forma templates are located at http://www.caiso.com/docs/2005/06/14/2005061416563264 66.html):

- An irrevocable and unconditional letter of credit issued by a bank or financial institution that is reasonably acceptable to the ISO;

- An irrevocable and unconditional surety bond issued by an insurance company that is reasonably acceptable to the ISO;
- An unconditional guaranty issued by a company that is reasonably acceptable to the ISO;
- A cash deposit in an escrow account maintained at a bank or financial institution that is reasonably acceptable to the ISO;
- A certificate of deposit in the name of the ISO issued by a bank or financial institution that is reasonably acceptable to the ISO;
- A payment bond certificate issued by a bank or financial institution that is reasonably acceptable to the ISO; or
- A prepayment to the ISO.

The ISO will maintain standard agreement forms related to the above types of Financial Security. In accordance with Section 12.1.2.1 of the ISO Tariff, the ISO will evaluate non-standard agreement forms for these types of Financial Security on a case-by-case basis. For those Market Participants or FTR Bidders that propose the use of a non-standard agreement form, the form would be subject to review and approval by the ISO Finance and Legal Departments. A Market Participant or FTR Bidder will be required to justify any proposed departures from the standard agreement form. The ISO shall have ten (10) Business Days from receipt of such form of Financial Security to evaluate it and determine whether it will be approved as reasonably acceptable. Significant departures from the standard agreement forms may not be accepted. The request is deemed denied if the ISO does not respond within ten (10) Business Days. It should be noted that if the need to post additional Financial Security was prompted by an additional Financial Security request based upon the latest Estimated Aggregate Liability calculation, the review process does not defer the Market Participant's obligation to post.

The standard that the ISO will use in establishing reasonable acceptability for issuing banks, financial institutions or insurance companies is that the institution have and maintain a minimum corporate debt rating of an "A-" by S&P, "A3" by Moody's, "A-" by Duff & Phelps, "A-" by Fitch or an equivalent short-term debt rating by any of these agencies.

In those cases where a Market Participant or FTR Bidder is a subsidiary or affiliate of another entity and would like to utilize the consolidated financial statements and other relevant information of that entity for obtaining credit, a signed corporate guaranty is required. A guarantor would be considered reasonably acceptable and a corresponding Financial Security Amount would be set based on the guarantor's credit evaluation according to the same procedures that a Market Participant or FTR Bidder would undergo as described in Section A-1.

Cash deposits held in escrow will be maintained in an interest bearing account. Interest will accrue to the Market Participant's or FTR Bidder's benefit and will be added to the Market Participant's or FTR Bidder's prepayment account on a monthly basis. Should a Market Participant or FTR Bidder become delinquent in payments, the Market Participant's or FTR Bidder's outstanding account balance will be satisfied using deposited funds. The Market Participant or FTR Bidder must take care to replenish used funds to ensure that it maintains a suitable level of cash to meet future financial obligations.

The ISO Tariff also permits Market Participants to make a prepayment of an upcoming bill due to the ISO. A prepayment may be used as a form of Financial Security. Prepayments to the ISO will be held in an interest-bearing account or another investment acceptable to the Market Participant and the ISO, and interest on the investment will accrue at the rate as provided for in the investment. Interest will accrue to the Market Participant's benefit and will be added to the Market Participant's prepayment account on a monthly basis. Due to the additional administrative effort involved in tracking and posting interest on such prepayments, the use of this option is not encouraged.

As provided in Section 12.1.2.3 of the ISO Tariff, the ISO shall not be held liable for any losses of funds held and invested by the ISO on the Market Participant's or FTR Bidder's behalf. Market Participants and FTR Bidders agree to bear any risk of loss of principal and/or interest of such funds. Funds will only be invested in bank accounts, high-quality money market funds or U.S. Government securities according to

the ISO investment policy, unless otherwise agreed to by the Market Participant or FTR Bidder and the ISO.

In accordance with Section 12.1.2.2 of the ISO Tariff, each Market Participant or FTR Bidder shall ensure that the financial instruments it uses for the purpose of providing Financial Security will not expire and thereby cause the Market Participant's or FTR Bidder's Aggregate Credit Limit to fall below the Market Participant's or FTR Bidder's Estimated Aggregate Liability. The ISO will treat a financial instrument that does not have an automatic renewal provision and that is not renewed or replaced within seven (7) days of its date of expiration as being out of compliance with the standards for Financial Security and will deem the value of such financial instrument to be zero, and will draw upon such Financial Security prior to its stated expiration if deemed necessary by the ISO.

PART C: ESTIMATED AGGREGATE LIABILITY CALCULATION

This section describes the approach used by the ISO to determine the Financial Security posting requirements for Market Participants. Different approaches are used for new Market Participants (those without experience data with the ISO or who have been previously inactive) and for Market Participants with such data.

C-1. New Market Participants

A new Market Participant (or a Market Participant that has previously been inactive) is required to post an initial Financial Security Amount to cover a minimum of 14 days of estimated obligations as well as additional Financial Security as obligations are incurred.

This posting requirement is based on anticipated scheduling/trading practices and overall volumes. The ISO has prepared a simple template (Appendix 2) that may be used to determine an initial posting requirement. The template is an Excel worksheet located at the New Market Participant Security Calculation link http://www.caiso.com/docs/2005/06/14/200506141656326466.html.

The ISO will monitor a Market Participant's ongoing security requirement by comparing actual obligations against the estimated obligations to determine if an additional Financial Security Amount is required using the method described in Section C.2. This approach permits a Market Participant to increase its Financial Security Amount as often as weekly until the time elapsed from initial participation equals the length of the ISO payment cycle. At that time, the Financial Security Amount should be sufficient to cover 102 days transactions on an ongoing basis (The "Level Posting Period", as described in the subsequent section).

C-2. Other Market Participants - Scheduling Coordinator Aggregate Liability Estimate (SCALE) and Estimated Aggregate Liability (EAL) Overview

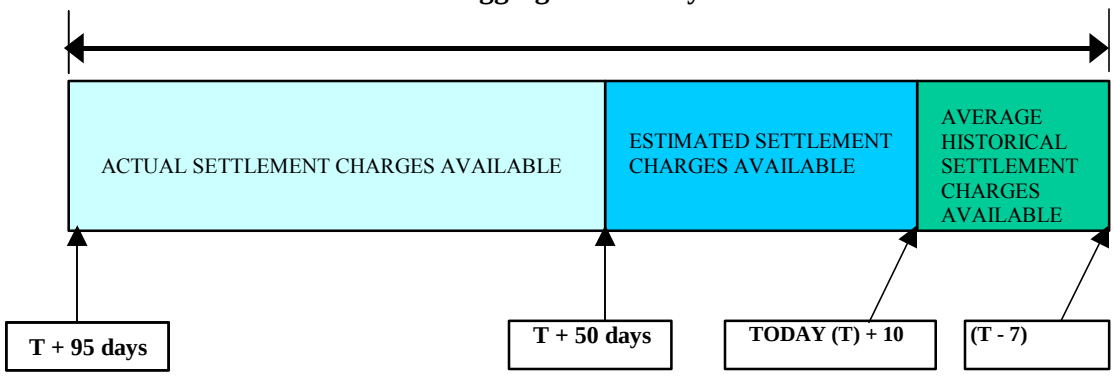
The Scheduling Coordinator Aggregate Liability Estimate (SCALE) application or an alternative method is used to calculate a Market Participant's Estimated Aggregate Liability, which is the estimate of unpaid obligations for a specified time period arising from charges described in the ISO Tariff.

The sum of a Market Participant's Unsecured Credit Limit and its Financial Security Amount is intended to provide coverage of not less than 100% of its Estimated Aggregate Liability. For a Market Participant that must post Financial Security because its Unsecured Credit Limit is not equal to or greater than its Estimated Aggregate Liability, the figures generated in determining the Estimated Aggregate Liability are normally the basis for determining each Market Participant's Financial Security posting requirement.

At any given time, the number of trade days of unpaid obligations to the ISO, based on the preliminary payment calendar, will be from 60-95 days, depending on the date of the last cash settlement. To avoid frequent changes to Financial Security posting requirements during the month and to allow a sufficient cushion of coverage given the allowed five day response time for Market Participants to post additional Financial Security, a "Level Posting Period" equal to 102 days is used as the basis for all Financial Security posting requirements.

The charges contributing to the Estimated Aggregate Liability are all charges outlined in the ISO Tariff. The Estimated Aggregate Liability calculation incorporates outstanding obligations, actual settlement charges, estimated settlement charges (calculated ten days after the trade date), and average historical settlement charges. The illustration below provides a representative example of what periods the different settlement charges cover in the Estimated Aggregate Liability calculation.

SC Aggregate Liability Estimate



NOTE: The *Average Historical Settlement Charges Available* could vary between seven (7) to fourteen (14) days.

Level Posting Period EALs are calculated as follows:

1. Aggregate all outstanding, actual settlement, predictive settlement and average historical predictive obligations through a specified calendar date. For example, if the EAL analysis was conducted on 8/1/2005, the Level Posting Period would begin on June 1, 2005 and end on August 13, 2005. The following obligations would be included in the analysis:

   - Outstanding AR/AP Obligations – Any open AR/AP balances, excluding balances covered by bankruptcies.
   - Final Invoice Obligation – Those obligations not paid on the preliminary invoice.
   - Actual Settlement Obligations – June 1, 2005 to June 9, 2005.
   - Predictive Settlement Obligations – June 10, 2005 through July 25, 2005.
   - Predictive Monthly Settlement Obligations - June 1, 2005 through July 25, 2005. For month-end Charge Types, daily amounts will be calculated to reflect those amounts as they are accrued.
   - Forecasted Settlement Obligations – July 26, 2005 through August 13, 2005 based on the average predictive settlement obligations from July 11, 2005 through July 25, 2005.

2. Calculate the daily average obligation by dividing the aggregate obligations calculated in step 1 above by the total number of days between June 1, 2005 and August 13, 2005.
3. Multiply the daily average obligation calculated in step 2 above by the level posting period days (i.e., 102 days).

Level Posting Period Days – The maximum number of days outstanding for the calendar year, based on the preliminary payment calendar, plus seven days for administrative purposes; currently set at 102 days.

Predictive Settlement Obligations – The obligations calculated by the settlement system using estimated generation, load and intertie MWhs (see Appendix 1 for a description of the MWh estimation process).

For a Market Participant that maintains multiple BAID numbers, the Estimated Aggregate Liability of the Market Participant as a legal entity will be calculated by summing the Estimated Aggregate Liabilities for all such BAID numbers and comparing the sum of the Estimated Aggregate Liabilities to the Aggregate Credit Limit of the Market Participant.

C-3. Adjustments to SCALE and Use of other ISO Data to Generate Estimated Aggregate Liability

The SCALE application provides liability estimates for Market Participants that, from an aggregate perspective as well as for most individual Market Participants, are the best liability estimates available to the ISO. Prior to the use of this approach, the ISO used a mechanical projection of available settlements data over the "blind spot" for each participant for which settlements data was not yet available. That approach did not consider changes in activity levels, or most changes in market prices.

Despite the significant improvement in accuracy from the use of the SCALE approach, there are times at which the ISO or a Market Participant observes that the SCALE application may be producing a liability estimate that appears to be inaccurate. The ISO has noted this situation when certain market parameters change such as the introduction of new market charges during Phase 1B of MRTU in 2004and during the C1 Control Area Footprint change in December 2005. In such instances, the ISO will attempt to revise the SCALE algorithms to appropriately reflect such changes, and may make manual adjustments to the SCALE results to reflect known issues. Alternatively, as a result of these or other causes, the SCALE application may also be considered to be temporarily inoperative by the ISO, and another approach to calculating liabilities must be used. This approach may also be used when:

- It becomes necessary to monitor the liabilities of a Market Participant on a more frequent basis than the SCALE application provides for;
- The ISO has determined that SCALE is not producing accurate Estimated Aggregate Liabilities for one or more Market Participants; or
- In situations that arise that the automated SCALE application cannot readily accommodate, e.g., a Market Participant bankruptcy where new BAIDs are established. In such a case, the previous activity levels in the "old" BAIDs may be representative of ongoing activities levels, but this data is not readily accessible to the SCALE application to estimate liabilities for the new post-bankruptcy BAIDs.

Market Participants may also recommend changes to the liability estimates produced by the SCALE application or an alternative ISO calculation through the dispute procedures noted in Part E.

C-3.1 Calculation of Estimated Aggregate Liability Using Available Settlements Data

If the ISO determines that the SCALE application is inoperative or producing liability estimates that are of questionable accuracy, the ISO will use an alternate approach to calculate Estimated Aggregate Liabilities for Market Participants. This backup approach will rely on available settlements data.

As noted in Section C-2, the Estimated Aggregate Liability amount consists of those trade days for which actual settlement charges are available and trade days for which actual settlements charges are not yet available. This alternative approach relies on a different method for estimating charges for the trade days for which actual settlements data is not available. Specifically, estimated charges for these trade dates are estimated based on average daily charges for trade dates for which settlements data is available.

The alternative EAL method differs from the SCALE method only in the manner it estimates data to represent liability for the "blind spot" in the payment calendar. It captures the same "actual" data as in the SCALE approach, specifically:

- Outstanding AR/AP Obligations – Any open AR/AP balances, excluding balances covered by bankruptcies.
- Final Invoice Obligation – Those obligations not paid on the preliminary invoice.
- Actual Settlement Obligations – Preliminary Settlements obligations up to the date of the latest Preliminary Statement.

The 102-day Level Posting Period is utilized in both SCALE and the alternative EAL approach. Depending on when the latest Preliminary and Final invoices were paid, there will be between about 8 and 40 days of unpaid actual Preliminary Statements. There can be an additional 20 to 30 days of unpaid Final statements as well, though those days are not counted toward the 102-day total because they are only incremental and are not representative of a complete day of activity.

The remainder of days in the 102-day Level Posting Period for which unpaid Preliminary Statements are not available must be estimated. The estimate is derived by taking a daily average of published, actual charges and multiplying by the number of remaining days in the Level Posting Period. The daily average is based on all outstanding unpaid Preliminary and Final activity and an additional amount of days (as described subsequently) of historical Final Statement activity. Due to the difficulty and pitfalls of gauging "blind spot" activity on historical statements, three methods will be utilized, varying only by the number of historical months used in the derivation of daily-average amounts.

The three methods will use the same outstanding charges (i.e., available Preliminary and Final activity) but will also consider a total of either one, two, or twelve months of historical data. The process of estimation is a relatively simple one, though each Market Participant's activity must be separated into Daily Market, Monthly Market, and GMC activity and estimated separately due to the difference in charge frequency. Appendix 1A contains additional details and an example calculation.

Once a daily average amount is derived for each market type and for each EAL method, they will be grouped by method and multiplied by the number of days remaining to fill the 102-day Level Posting Period. Thus, three Level Posting Period Estimated Aggregate Liability calculations will result. FERC Fees and other outstanding AR/AP balances will be added to each figure and the sum for each method will be divided by 0.9 in order to account for the ISO's stated policy for Financial Security of not more than a 90% utilization rate. Any shortfall between the 90%

utilization amount of the EAL and the posted Financial Security will be considered as a potential request for additional Financial Security.

Any Market Participant that would tentatively be required to post additional Financial Security based on the Estimated Aggregate Liability calculation using any of these three methods is flagged for additional review. ISO staff will review the preliminary liability estimates resulting from the use of 12 months, 2 months and 1 months of historical settlements data. Such information is reviewed in a numeric and graphical format. ISO staff aims to select the method that best represents Market Participant activity for which settlements data is not yet available. If ISO staff determines that the Estimated Aggregate Liability for the Market Participant exceeds 90% of the Market Participant's Aggregate Credit Limit, the ISO will request additional Financial Security and will provide the supporting calculation used for the Estimate Aggregate Liability amount.

C-4. Special Circumstances

The ISO's goal is to ensure that active as well as inactive Market Participants (to the extent they are not covered by their Unsecured Credit Limits) post adequate Financial Security to cover all known and reasonably estimated potential liabilities. Various charges and collateral issues sometimes arise which require special consideration.

The ISO intends to include the following charges in the Estimated Aggregate Liability calculation, if and when such data is available, and will require Market Participants to post Financial Security accordingly. The ISO's planned Settlement and Market Clearing system upgrade is scheduled for implementation in November 2007, at which time improved data for certain of these transactions is anticipated to be available.

- **Daily Adjustments and Disputes** – Charges associated with daily adjustments and disputes that are regularly calculated by the settlement system will be included in the liability estimation calculations as the charges are calculated. There should generally be no need to attempt to forecast these amounts since they are typically relatively small and usually affect many Market Participants.

- **Refund Orders** – The ISO will assess its ability to reasonably calculate the charges associated with a refund before the ISO's settlement system is rerun. If the ISO can reasonably apportion the refund to specific Market Participants, it will include the amounts in the liability estimation process and request security accordingly. If the ISO deems that complexities of a refund order preclude it from reasonably assessing the liabilities, it will not make a security request until the refund is processed through the settlement system. However, the ISO will make available an aggregate forecast of the refund liabilities, if at all possible, to Market Participants for informational purposes only.

- **Good Faith Negotiations** – In general, Good Faith Negotiations (GFN) tend to affect the transactions of an individual Market Participant, which in turn may affect a few or many other Market Participants. Transactions associated with GFNs will be handled in the same manner as transactions associated with Refund Orders.

Other special circumstances include:

- **Debtor/Creditor Market Participants leaving the market or incurring substantial activity level changes** – Those Market Participants that are exiting the ISO markets, or that have changed their business practices resulting in substantially reduced participation in the ISO markets, will be required to maintain a Financial Security Amount at least equal to five percent (5%) of the absolute value of the peak monthly net charges from their beginning participation date to their last participation date or the date the substantial

change occurred. The ISO will use this Financial Security posting requirement as a base amount and reserves the right to increase or decrease the base amount depending on the number of settlement reruns in the queue and the estimated value of those settlement reruns. The five percent (5%) residual Financial Security posting will be retained for a period of one year, unless specific circumstances warrant a change in this retention period (e.g., pending FERC ordered adjustments).

- **Past due amounts owed to SCs are not considered part of an SC's security posting**. This treatment is necessary if the ISO is to maintain the integrity of the overall settlement system, which requires that each month be settled separately. Each trade month consists of creditors and debtors whose receivables and obligations vary over time. To the extent that amounts owed to an SC related to defaults in previous months are included in the liability estimation calculation and permitted to reduce that SC's current posting requirements, the ISO will have no means to enforce the payment obligation of that SC to pay current invoices rather than refuse payment in an attempt to recoup previous past-due amounts owed to them.

C-5. Estimated Aggregate Liability Review

As provided in Section 12.4 of the ISO Tariff, Estimated Aggregate Liabilityis used to determine Financial Security posting requirements and is to be used as the basis for additional Financial Security requests, particularly when a Market Participant's calculated liability estimate exceeds 90% of its Estimated Aggregate Liability.

A Market Participant has five (5) business days to review the request for additional Financial Security and submit proposed changes that must be agreed to by the ISO. Within the five (5) business days, the Market Participant must either demonstrate to the ISO's satisfaction that the ISO's Financial Security request is all or partially unnecessary, or post the required Financial Security Amount calculated by the ISO. If the ISO and Market Participant are unable to agree on the appropriate level of Financial Security during the five (5) business day review period, the Market Participant must post the additional Financial Security and continue the dispute procedure as described in Part E. Any excess Financial Security amounts will be returned to the Market Participant if the dispute process finds in favor of the Market Participant.

C-6. Financial Security Posting Requirements

This section describes the process for determining when additional Financial Security is required and how the request for additional Financial Security is communicated to the Market Participant.

C-6.1. Financial Security Requests

As described above, to the extent a Market Participant's Unsecured Credit Limit is less than its Estimated Aggregate Liability, the Market Participant must post a Financial Security Amount. The determination of a required/recommended Financial Security Amount is based on a Market Participant's most recent ISO Estimated Aggregate Liability calculation. The ISO recommends that each Market Participant maintain an Aggregate Credit Limit such that its Estimated Aggregate Liability does not exceed 90% of its Aggregate Credit Limit. The calculation is as follows:

Recommended Aggregate Credit Limit = (Estimated Aggregate Liability) / (0.90)

The 90% level is specified in the ISO Tariff and is used as the basis for the Financial Security Amount recommended by the ISO. A Market Participant must provide an additional Financial Security Amount when its obligations reach 100 percent of its Aggregate Credit Limit. However, the ISO recommends providing additional Financial Security at the 90% level, because when a

Market Participant's Estimated Aggregate Liability exceeds 100% of its Aggregate Credit Limit, the ISO may be required to impose enforcement actions.

The Estimated Aggregate Liability calculated by the ISO for a Market Participant may fluctuate, and at times this may result in swings in Financial Security posting requirements. To the extent that the Estimated Aggregate Liability exceeds the Aggregate Credit Limit at any time, a Market Participant may be subject to enforcement actions including not being entitled to submit a schedule to the ISO. Thus, the ISO recommends that Market Participants maintain a margin of Aggregate Credit Limit above their maximum anticipated Estimated Aggregate Liability.

The Estimated Aggregate Liability is updated weekly for each Market Participant and is used to determine if additional Financial Security needs to be posted. Based on a Market Participant's Aggregate Credit Limit utilization level (which is the EAL divided by Aggregate Credit Limit), the following actions will be taken at each level listed:

Aggregate Credit Limit Utilization %	**Action**
< 50%.	No notice or action taken.
≥50% and < 70%	Market Participant notified for information only.
≥70% and < 90%	Market Participant notified of a *recommended* security increase. The ISO recommends, but does not require, that an additional posting is made to maintain the SCALE at or below 70%.
≥90%	The ISO *requests* that a Market Participant increase the posting amount within five business days so that the security utilization does not exceed 90 percent. If the Market Participant takes no action in response to the recommendation to post additional security, upon reaching 100 percent security utilization, they will be subject to the enforcement provisions of the ISO Tariff as described in Section D, Enforcement, including potential rejection of schedules.

C-6.2. Financial Security Requests Communication

Each week the ISO Finance calculates each Market Participant's Estimated Aggregate Liability and notifies the ISO's customer service representatives of the Estimated Aggregate Liability amount and any recommended increases in the Market Participant's Financial Security Amount. These communications contain specific information regarding the amount each Market Participant needs to post Financial Security in order to maintain the recommended 90% ratio described above as well as the minimum amount needed so that the Market Participant's Estimated Aggregate Liability does not exceed its Aggregate Credit Limit.

The ISO customer service representative is to contact any Market Participant for which an increase in Financial Security is recommended or required within one (1) business day.

The customer service representative should copy ISO Finance on all security related client correspondence. The ISO customer service representatives will communicate with the ISO Finance and Market Participants to address questions related to the request.

A required increase in the Financial Security Amount is to be resolved within five (5) business days. Each Market Participant not in compliance with the requirement that its Estimated Aggregate Liability be less than its Aggregate Credit Limit is subject to enforcement procedures as described in Part D.

C-6.3. FTR Auction Financial Security Requirements

The credit requirements related to participation in the ISO's annual Firm Transmission Rights (FTR) are the same as those for other market obligations. Auction requirements are set forth in the FTR Bidders Manual published annually by the ISO. A FTR Bidder's ACL must be sufficient to not only cover ongoing estimated liabilities but also the liabilities resulting from potential winning bids. Each FTR Bidder may choose to designate a portion of their UCL and/or posted Financial Security specifically for the FTR auction by notifying the ISO of the FTR Bidder's intent. Alternatively, the FTR Bidder may choose to post additional Financial Security solely to cover their participation in the FTR auction by notifying the ISO of the purpose for the additional Financial Security.

PART D. ENFORCEMENT

Following the date on which a Market Participant commences trading, if a Market Participant's Estimated Aggregate Liability, as calculated by the ISO, at any time exceeds its Aggregate Credit Limit, the ISO may take any or all of the following actions in accordance with Section 12.5 of the ISO Tariff:

(a) The ISO may withhold a pending payment distribution.

(b) The ISO may limit trading, which may include rejection of Schedules and/or limiting other ISO market activity. In such case, the ISO shall notify the Market Participant of its action and the Market Participant shall not be entitled to submit further Schedules to the ISO until the Market Participant posts an additional Financial Security Amount that is sufficient to ensure that the Market Participant's Aggregate Credit Limit is at least equal to its Estimated Aggregate Liability.

(c) The ISO may require the Market Participant to post an additional Financial Security Amount in lieu of an Unsecured Credit Limit for a period of time.

(d) The ISO may restrict, suspend, or terminate a Market Participant's Service Agreement.

In addition, the ISO may restrict or suspend a Market Participant's right to schedule or require the Market Participant to increase its Financial Security Amount if at any time such Market Participant's potential additional liability for Imbalance Energy and other ISO charges is determined by the ISO to be excessive by comparison with the likely cost of the amount of Energy scheduled by the Market Participant.

PART E. DISPUTE PROCEDURES

The ISO provides Market Participants the ability to dispute the Estimated Aggregate Liability calculated by the ISO and, as a result, the ISO may reduce or cancel a requested Financial Security adjustment. The following steps are required for a Market Participant to dispute a Financial Security request resulting from the ISO's calculation of Estimated Aggregate Liability:

1. Request by the Market Participant to review the ISO calculation.

2. Reasonable and compelling situation presented, as determined by the Market Participant's ISO client representative.

3. Documentation of facts and circumstances that evidence that the ISO's calculation of Estimated Aggregate Liability results in an excessive and unwarranted Financial Security posting requirement.

    a. Examples include:
        i. Issues related to non-recurring retroactive charges.

ii. Demonstrable changes in expected obligations as a result of physical changes (new capacity, loss of customers).
iii. Other issues.

b. Presentation of a reasonable alternative Estimated Aggregate Liability.
c.

4. Approval by the ISO Manager and/or Director of Customer Services and Industry Affairs and approval by the ISO Treasurer.

5. The ISO may decline to adjust the initial Estimated Aggregate Liability, as calculated using the SCALE application, if the Market Participant has had Financial Security shortfalls in the past 12 months (i.e., it has been shown that the Market Participant's Aggregate Credit Limit at times during the preceding 12 months has been insufficient to cover the Market Participant's Estimated Aggregate Liability).

   In no such case shall an ISO request for increased Financial Security remain outstanding for more than five (5) business days. Either the above process is to be completed within five (5) business days from the date of the ISO request for additional Financial Security, or the Market Participant is to post additional Financial Security within the five (5) business days and continue this process, which may result in a return of posted Financial Security back to the Market Participant if the results of the dispute process are found to favor the Market Participant.

   Factors for consideration in the event these procedures are utilized include:

   Weighing the risk of using the lower figure to the potential detriment of market creditors if the Market Participant is under-secured and defaults, against the desire not to impose additional potentially unwarranted costs on a Market Participant.

   Equity and consistency of treatment of Market Participants in the dispute procedure.

   The evidentiary value of the information provided by the Market Participant's in the dispute procedure.

APPENDIX 1: Scheduling Coordinator Aggregate Liability Estimate Measurement File Development Process

INTRODUCTION

The following information provides background and an overview of the operation of the SCALE liability estimation process. This section focuses on the measurement file development process to develop proxies for missing meter data. This allows the ISO to use available operational to estimate current liabilities.

DEVELOPMENT PROCESS

Defined Terms

EMS Utility Distribution Control Area (UDC) Load – The ISO control area load MWhs aggregated at the PG&E, SCE and SDG&E level.

Generation Deviation Allocation Flag – The generation deviation allocation flag denotes which Market Participant load profiles are allocated generation deviation/Unaccounted for Energy (UFE) MWhs.

Load Profiles

Annual Load Profile – Load profile developed from actual meter MWhs for the period of Trade Date (T) + 50 to T+415.

Current Load Profile – Load profile developed from actual meter MWhs for period of T+50 to T+80.

Schedule Load Profile – Load profile developed from scheduled meter MWhs for the period of T+1 to T+49.

Seasonal Load Profile – Load profile developed from actual meter MWhs for the prior season.

Short-Term Schedule Load Profile - Load profile developed from scheduled meter MWhs for the period of T+1 to T+14.

Load Profile Adjustment Percentage – The load profile adjustment percentage is calculated as the percentage variance between actual metered load and allocated EMS UDC Load. This percentage is utilized to develop actual metered load, utilized by the settlement system, from allocated EMS UDC Load.

Meter Load to Scheduled Load Adjustment Percentage – The meter load to scheduled load adjustment percentage is calculated as the variance between actual meter load and scheduled load. The percentage is utilized to create representative meter load from scheduled load.

Off-Peak – This term represents the day of the week to which a load profile corresponds. The Off-Peak days of the week include: Saturday, Sunday and Holidays.

On-Peak –This term represents the day of the week to which a load profile corresponds. The On-Peak days of the week include: Monday, Tuesday, Wednesday, Thursday and Friday.

Other Adjustment Percentage – For a Market Participant whose load profiles and adjustment percentages do not reflect its load, the other adjustment percentage approach is utilized. This approach is only rarely used.

Use Meter Load to Scheduled Load Adjustment Percentage Flag – This flag identifies those calculated Market Participant load profiles that are subsequently adjusted by the meter load to scheduled load adjustment percentage.

Use Scheduled Load Flag – This flag identifies those Market Participants where utilization of scheduled load a proxy for metered load is appropriate.

Market Participant Liability Estimations

In 2003, the focus of the Scheduling Coordinator Aggregate Liability Estimation (SCALE) project was on the development of settlement statements seven days after the trade date using a system that is essentially a copy of the settlement system with missing load, generation and intertie data derived from a combination of meter, telemetry and estimated data from other systems. In order for the SCALE application to effectively and accurately calculate participant liabilities, three essential data inputs are needed: load, generation and intertie MWhs. It was determined that 75 to 80 percent of generation and intertie MWhs are derived from the ISO polled meter data stored in the ISO's Data Warehouse. However, the load MWhs were not available until 45 days after the trade date. Thus, the main focus of the SCALE project team's efforts to was on the estimation of load data. The analysis conducted produced the following findings:

1. Utilization of current actual meter load profiles, which are based on meter data that is 50 to 80 days old, to allocate EMS UDC Load, did not alone accurately reflect a Market Participant's current position in the market. For example, a Market Participant's load profile based on past data would not accurately reflect a situation where it has transferred its load/customers to another Market Participant.

2. Utilization of annual load profiles to allocate EMS UDC Load in many instances did not reflect load increases or decreases that appear over time. For example, since September 2001, certain Market Participants have acquired a substantial amount of load from other Market Participants, but the annual load profiles generated did not reflect this load shift.

3. Utilization of schedules to estimate system load and to derive participant liabilities did not reflect the actual daily system load or participant imbalances. This was mainly due to a Market Participant's ability to schedule whatever amount of load that it chooses. Analysis of Market Participant scheduling patterns has shown that many Market Participants' schedules are closely related to their actual metered quantities. However, Market Participant scheduling practices may not be consistent.

4. After conducting an analysis of the load estimation methodologies above, it was determined that all three methods should be combined to provide for a more accurate load estimate. The methodology, outlined below, includes the information gathered through the liability estimation process.

Additional areas that the SCALE team worked on were the estimation of the remaining 15 to 25 percent of missing generation and intertie MWhs. The team developed a methodology to estimate the remaining generation and intertie MWhs, and an explanation of the methodology is outlined below.

Load Estimation Methodology

As mentioned in the previous section, three approaches were considered to estimate load MWhs and each had significant shortcomings that precluded them from being utilized exclusively. By utilizing each of the methodologies in conjunction with each other, a proxy for metered load was

developed that more closely represented each participant's position in the market. The following are the steps created to develop a Market Participant's load estimate.

1. **Develop Load Profiles** - Development of each Market Participant's "On-Peak" (Monday through Friday) and "Off-Peak" (Saturday, Sunday and Holidays) hourly load profiles by UDC area. The load profiles developed consist of:
   - Annual Load Profiles,
   - Seasonal Load Profiles,
   - Current Load Profiles,
   - Scheduled Load Profiles, and
   - Short-Term Scheduled Load Profiles.
2. **Select Load Profile** – Once the load profiles are developed for a given time period, the next step in the load estimation process is to determine which load profile (Annual, Seasonal, Current etc) most closely reflects a Market Participant's actual position in the market. For example, the EMS UDC Load from 12/16/2002 to 1/15/2003 is allocated to each of the load profiles listed above. Next, the allocated MWhs for each set of profiles is compared against the actual metered MWhs for the same time period 12/16/2002 to 1/15/2003. The load profile that best represents a Market Participant's actual meter MWhs is utilized for subsequent load allocations.
3. **Calculate / Select Load Profile Adjustment Percentages and Load Profile Application Flags** – The following adjustment percentages and load profile application flags, which are defined above, are calculated or selected to be utilized in subsequent calculations:
   - Load Profile Adjustment Percentage,
   - Meter Load to Scheduled Load Adjustment Percentage,
   - Other Adjustment Percentage,
   - Use Meter Load to Scheduled Load Adjustment Percentage Flag, and
   - Use Scheduled Load Flag.

   (note: the results of steps 1 thru 3 are utilized for a designated period, such as 30 days)

4. **Validate EMS UDC Load** – EMS UDC Load validation for each trade date is conducted to ensure that the data derived from EMS does not include significant outlier MWhs. The calculation includes comparing an historical EMS load profile (T+1 to T+50) to the current trade date load profile. Where the current load profile MWh does not meet the 15 percent tolerance level, the current EMS MWh value is adjusted to within tolerance.

5. **Allocate EMS UDC Load** – Next, the ISO will utilizes the selected load profile for determining the MP's hourly load to allocate EMS UDC Load. The following steps are required for the allocation of EMS UDC Load:
   i. The EMS UDC Load is allocated to MP's based on the following formula (all calculations are conducted on an hourly basis):
      - Where Use Schedule Load Flag = "True"; Scheduled Load * (1+Meter Load to Scheduled Load Adjustment Percentage)

- Where Use Schedule Load Flag = "False" and Use Meter Load to Scheduled Load Adjustment Percentage Flag = "True", EMS UDC Load * Selected Load Profile / 1000 * (1+ Load Profile Adjustment Percentage) * (1+ Other Adjustment Percentage) * (1+ Meter Load to Scheduled Load Adjustment Percentage),

- Else, EMS UDC Load * Selected Load Profile / 1000 * (1+ Load Profile Adjustment Percentage) * (1+ Other Adjustment Percentage)

ii. The value of Hourly EMS UDC Load * Selected Load Profile is divided by 1000 because the hourly load profile percentages derived are multiplied by 1000 for data representation purposes.

6. **Calculate Generation Deviation / Unaccounted for Energy (UFE) Quantity by UDC** - For each UDC, a Generation Deviation / UFE calculation is completed, which provides a residual amount of Load MWhs that are allocated to designated Market Participants on a *pro rata* basis. The purpose of the calculation and load MWh allocation is to minimize Charge Type 406 UFE charges. The UFE calculation is outlined in the settlement and billing protocols under CT 406. The allocation process is as follows (all calculations are conducted on an hourly basis):

   i. Where Generation Deviation Allocation Flag = "False", MP Load + (UDC UFE *MP Load / Total UDC Load where Generation Deviation Allocation Flag = "False").

7. **Load Distribution and Upload** – Upon deriving the load MWhs to be utilized in the settlement statement calculation, the MWhs are distributed to each Market Participant's valid resources IDs in the following manner and then uploaded into the SCALE application.

   i. Development of a list of valid metered and scheduled resources utilized by each MP over a given time period (T+1 to T+80).

   ii. Allocate the estimated load to the valid resources on a weighted basis by hour. For all resources that have both metered quantities and scheduled quantities, metered quantities will be utilized for weighting purposes. Resources that have scheduled quantities and no metered quantities are assumed to be recently utilized resources and scheduled quantities will be used for weighting purposes.

   iii. Allocate the resource quantities calculated above evenly across the six sub-hour interval levels for upload into the measurements table in the SCALE application.

Generation Estimation Methodology

As mentioned above, at T+7 approximately 15 to 25 percent of generation meter data is not available. The following is an explanation of the methodology utilized to develop a proxy for the missing generation meter data.

The ISO determined that the missing generation data consists of the following:

1. The ISO polled unit MWhs that were either not available at T+7 or were being worked on by the metering department at the time of the T+7 data push, and
2. Qualifying Facility (QF) unit and other non-polled unit MWhs.

The process for determining the remaining generation data is based on EMS and schedule data.

1. **Download T+7 Meter Data Acquisition System (MDAS) Generation Data** – For the trade date being worked on, all generation data available in the T+7 measurement table is downloaded for analysis purposes.
2. **Download Scheduled Generation Data** – From Market Operation's Scheduling Infrastructure (SI) database, download hourly scheduled generation by resource ID.
3. **Download Real Time (RT) Dispatch Data** – From Market Operation's SI database, download hourly real time dispatched data by resource ID.
4. **Download EMS Data from Plant Information (PI)** – A table has been developed from information provided by Market Operations that contains approximately 800 generation resource IDs mapped to the appropriate PI tags. Using the PI tags, generation unit hourly EMS MWhs are downloaded from PI.
5. **Download Actual Meter & Schedule Data** – From the Data Warehouse, download actual metered and scheduled quantities for a period of T+50 to T+80 for analysis purposes.
6. **Utilization of T+7 MDAS Generation Data** – Where T+7 MDAS generation data exists for a particular resource, even if the measurement quantity is zero, use this value. (Between 75 and 85 percent of all generation MWhs.)
7. **Utilization of EMS Generation Data** – Where MDAS data is not available and Dispatched Generation MWh >0 and EMS MWh >0, use EMS MWhs. (Approximately 18.75 percent of all generation MWhs.)
    a. Dispatched Generation MWh = Scheduled Generation MWh + RT Dispatched Generation MWh
    b. Where the EMS MWh * 1.15 is greater than the maximum generation capacity of the unit utilize the maximum generation capacity of the unit.
8. **Utilization of Dispatched/Scheduled Generation MWhs** – Where MDAS data is not available and Dispatched Generation MWh >0 and EMS MWh = 0, use Adjusted Dispatched / Scheduled Generation MWh. (Approximately 6.25 percent of all generation MWhs.)
    a. Adjusted Dispatched Generation MWh =
        i. For all Dispatched / Scheduled Generation MWhs >=1 MWh, Dispatched / Scheduled Generation MWhs* 1+(Hourly Metered vs. Scheduled Generation Variance Percentage)
    b. Resource Historical Metered vs. Scheduled Variance Percentage (T+50 to T+80) = (average hourly metered MWh – average hourly scheduled MWh) / average hourly scheduled MWh
9. **Upload the Developed MWhs to the SCALE Application** - Allocate the resource quantities calculated above evenly across the six sub-hour interval levels for upload into the measurements table in the SCALE application.

Intertie/Intratie (TIE) Estimation Methodology

Currently, 75 to 80 percent of the TIE data is available from the ISO polled meters. The process for determining the remaining intertie MWhs is based on the utilization of EMS data and allocated load MWhs derived in the Load Estimation Methodology for various intraties.

1. **Download T+7 MDAS Intertie Data** – For the trade date being estimated, all TIE data available in the T+7 measurement table is downloaded for analysis purposes.
2. **Download EMS Data from PI** – A table has been developed from information provided by Market Operations that contains TIE resource IDs mapped to the appropriate PI tags. Using the PI tags, TIE hourly EMS MWhs are downloaded from PI.
3. **Utilization of T+7 MDAS Intertie Data** – Where T+7 MDAS TIE data exists, use MDAS data. (Approximately 84 percent of all TIE MWhs.)
4. **Utilization of EMS Intertie Data** – Where MDAS data is not available use the EMS data. (Approximately 13 percent of all TIE MWhs.)
5. **Utilization of Load Data** – For intratie IDs, utilize the amount calculated as load as the intratie MWhs where appropriate. (Approximately 3 percent of all TIE MWhs.)
6. **Upload the Developed MWhs to the SCALE Application** - Allocate the resource quantities calculated above evenly across the six sub-hour interval levels for upload into the measurements table in the SCALE application.

SCALE Data Development Conclusion

The above steps describe how missing meter MWh data is developed for an estimated T+7 settlement run. Further enhancements to this process may be forthcoming as the process is transitioned to a permanent software tool, planned for November 1, 2007 when the ISO's new Settlement and Market Clearing System (SaMC) is implemented.

APPENDIX 1A: ALTERNATIVE ESTIMATED AGGREGATE LIABILITY CALCULATION

To assist Market Participants in understanding and verifying the ISO's alternative EAL calculation, the following section provides additional details and an example calculation. As described in Section 3.1, the ISO initially evaluates a Market Participant's liability by deriving three estimates which vary only by the number of months used in derivation of the daily average liability amounts. ISO Staff review the preliminary estimates to determine which appears to be most representative of the likely actual liability, and may request additional collateral based on that estimate. A summary report detailing the alternative EAL calculation will be provided to any Maket Participant requested to post additional security, or at any time when requested by the Market Participant. The report will highlight only the method that is deemed by the ISO to be most representative of the Market Participant's liability, however all three methods are available upon request as well.

This Estimated Aggregate Liability (EAL) Report presents most of the details of the calculation, which should be verifiable by the Market Participant using published Settlements Statements. Adding all outstanding, unpaid, published Settlements activity to an estimate of the remaining liability in the 102-day period results in the Level Posting Period EAL.

For example, assume that the EAL is calculated on Friday, June 16, 2006. On this day there are 23 days of published Preliminary Statements along with 4 days of Final Statements for the month of April. All of this activity will be summed for April and will account for 23 days out of the required 102 days. The Preliminary Statement has been paid for March; therefore no days in March will be counted in the Level Posting Period. However, there are still incremental charges in March on Final Statements that have been invoiced but not paid, and therefore will be included in the liability amount.

Now an estimate must be derived for the remaining seven days of April, along with an additional 72 days that make up the Level Posting Period (23+7+72=102). The estimate is based on a calculated daily average amount for all Charge Types. For simplicity, the Charge Types are aggregated into three categories: Daily Market (Imbalance Energy, Ancillary Services, etc.), Monthly Market (Wheeling, Transmission, etc), and GMC. The following table entitled "**Charge Type Category List"** lists all Charge Types and their category designation.

The averages for all three categories will be calculated using the same time period, based on either one, two or twelve months of historical Settlements data. In the one-month method, the time-period for derivation of daily averages will include 23 days of April published data, 30 days of March published data (because the month is still open), and one additional month of previously paid Settlement activity, specifically the month of February. For purposes of our example, assume that all outstanding, published obligations net to a total of $7,000.

To derive a daily average amount for the category of 'Daily Market' charge types, sum all charge type amounts in this category (see attached table) from February 1 to April 23 and divide by 82 (28+31+23). Assume the result is $100 per day.

To derive the daily average of 'Monthly Market' charges, sum all charge type amounts in this category from February 1 to March 31. Due to the fact that these charge types accrue only on the last day of the month, there is no reason to consider the range of April 1 to April 23 at this time. Divide the amount by 60 days for the two-month period. Assume the result is $50 per day.

Lastly, derive the 'GMC' category charges in the same manner as the 'Monthly Market' charges and divide by 60. Assume the result is $25.

Now combine the results and calculate 102-day Liability.

Outstanding obligations: calculated above for the 23 days of April Prelims and 30 days of March Finals, includes 'Daily Market', 'Monthly Market' (incremental Final), and 'GMC' (incremental Final)

$ 7,000 *(23 days)*

'Daily Market' Estimate: 7 days in April, 31 days in May, 30 days in June, 11 days in July

$ 100 * (7+31+30+11) = $ **7,900** *(79 days)*

'Monthly Market' Estimate: 30 days in April, 31 days in May, 30 days in June, 11 days in July

$ 50 * (30+31+30+11) = **$ 5,100** (102 days)

'GMC' Estimate: 30 days in April, 31 days in May, 30 days in June, 11 days in July

$ 25 * (30+31+30+11) = **$ 2,550** (102 days)

Total 102-day Level Posting Period EAL:

$ 7,000 + $ 7,900 + $ 5,100 + $ 2,550

= $ 22,550

The other two methods are calculated in the same manner while adding additional months of historical Settlements data.

Charge Type Category List:

Frequency	Charge Type	Charge Type Description	Service Type
Daily	1	Day-Ahead Spinning Reserve due SC	Ancillary Services
Daily	2	Day-Ahead Non-Spinning Reserve due SC	Ancillary Services
Daily	3	Day-Ahead AGC/Regulation due SC	Ancillary Services
Daily	4	Day-Ahead Replacement Reserve due SC	Ancillary Services
Daily	5	Day-Ahead Regulation Up due SC	Ancillary Services
Daily	6	Day Ahead Regulation Down due SC	Ancillary Services
Daily	24	Dispatched Replacemnt Res (Bid-in) Capacity Withhold	Ancillary Services
Daily	51	Hour-Ahead Spinning Reserve due SC	Ancillary Services
Daily	52	Hour-Ahead Non-Spinning Reserve due SC	Ancillary Services
Daily	53	Hour-Ahead AGC/Regulation due SC	Ancillary Services
Daily	54	Hour-Ahead Replacement Reserve due SC	Ancillary Services
Daily	55	Hour Ahead AGC/Regulation Up due SC	Ancillary Services
Daily	56	Hour AHead AGC/Regulation Down due SC	Ancillary Services
Daily	61	Hour-Ahead RMR Preempted Spinning Reserve	RMR
Daily	62	Hour-Ahead RMR Preempted Non-Spinning Reserve	RMR
Daily	64	Hour-Ahead RMR Preempted Replacement Reserve	RMR
Daily	65	Hour-Ahead RMR Preempted Regulation Up	RMR
Daily	66	Hour-Ahead RMR Preempted Regulation Down	RMR
Daily	71	Real Time RMR Preempted Spin Reserve (DA Price)	RMR
Daily	72	Real Time RMR Preempted Non-Spin Reserve (DA Price)	RMR
Daily	74	Real Time RMR Preempted Replacement Reserve (DA Price)	RMR
Daily	75	Real Time RMR Preempted Regulation Up (DA Price)	RMR
Daily	76	Real Time RMR Preempted Regulation Down (DA Price)	RMR
Daily	81	Real Time RMR Preempted Spin Reserve (HA Price)	RMR
Daily	82	Real Time RMR Preempted Non-Spin Reserve (HA Price)	RMR
Daily	84	Real Time RMR Preempted Replacement Reserve (HA Price)	RMR
Daily	85	Real Time RMR Preempted Regulation Up (HA Price)	RMR
Daily	86	Real Time RMR Preempted Regulation Down (HA Price)	RMR
Daily	101	Day-Ahead Spinning Reserve due ISO	Ancillary Services
Daily	102	Day-Ahead Non-Spinning Reserve due ISO	Ancillary Services
Daily	103	Day-Ahead AGC/Regulation due ISO	Ancillary Services
Daily	111	Spinning Reserve due ISO	Ancillary Services
Daily	112	Non-spinning Reserve due ISo	Ancillary Services
Daily	114	Replacement Reserve due ISO	Ancillary Services
Daily	115	Regulation Up due ISO	Ancillary Services

Frequency	Charge Type	Charge Type Description	Service Type
Daily	116	Regulation Down due ISO	Ancillary Services
Daily	124	Dispatched Replace Res (Self-Prov.) Capacity Withhold	Ancillary Services
Daily	130	Insufficient Energy in Response to ISO Instructions	Misc
Daily	131	Reduct. in Avail. Cap. due to Uninst. Dev. due ISO	Misc
Daily	141	No Pay Charge - Spinning Reserve	No Pay
Daily	142	No Pay Charge - Non-Spinning Reserve	No Pay
Daily	144	No Pay Charge - Replacement Reserve	No Pay
Daily	145	No Pay Charge - Regulation Up	No Pay
Daily	146	No Pay Charge - Regulation Down	No Pay
Daily	151	Hour-Ahead Spinning Reserve due ISO	Ancillary Services
Daily	152	Hour-Ahead Non-Spinning Reserve due ISO	Ancillary Services
Daily	153	Hour-Ahead AGC/Regulation due ISO	Ancillary Services
Daily	201	Day-Ahead Intra-Zonal Congestion Incs/Decs Settlement	Congestion
Daily	202	Day-Ahead Intra-Zonal Congestion Charge Refund	Congestion
Daily	203	Day-Ahead Inter-Zonal Congestion Settlement due SC	Congestion
Daily	204	Day-Ahead Inter-Zonal Congestion Settlement due TO	Congestion
Daily	251	Hour-Ahead Intra-Zonal Congestion Settlement	Congestion
Daily	252	Hour-Ahead Intra-Zonal Congestion Charge Refund	Congestion
Daily	253	Hour-Ahead Inter-Zonal Congestion Settlement due SC	Congestion
Daily	254	Hour-Ahead Inter-Zonal Congestion Settlement due TO	Congestion
Daily	255	Hour-Ahead Inter-Zonal Congestion Debit to TOs	Congestion
Daily	256	Hour-Ahead Inter-Zonal Congestion Debit due SC	Congestion
Daily	271	Real-time Intra-zonal Congestion INC/DEC Settlement	Imbalance Energy
Daily	272	Real-time Above MCP Costs for Non-Market Dispatches	Excess Costs
Daily	301	Supplemental and A/S Energy	Reliability
Daily	303	Ex-Post Replacement Reserve due ISO (Dispatched)	Ancillary Services
Daily	304	Ex-Post Replacement Reserve due ISO (Undispatched)	Ancillary Services
Daily	353	Contracted Black Start due SC	Reliability
Daily	401	Instructed Energy	Imbalance Energy
Daily	402	Generation Deviation Settlement	Imbalance Energy
Daily	403	Load Deviation Settlement	Imbalance Energy
Daily	404	Export Deviation Settlement	Imbalance Energy
Daily	405	Import Deviation Settlement	Imbalance Energy
Daily	406	UFE Settlement	Imbalance Energy
Daily	407	Uninstructed Energy	Imbalance Energy
Daily	410	Unscheduled RMR Energy	Imbalance Energy
Daily	451	Real-Time Intra-Zonal Congestion Incs/Decs Settlement	Congestion
Daily	452	Real-Time Intra-Zonal Congestion Charge/Refund	Congestion

Frequency	Charge Type	Charge Type Description	Service Type
Daily	481	Excess Cost for Instructed Energy	Imbalance Energy
Daily	485	Insufficient Response to AWE Instruction	Penalties
Daily	487	Allocation of Excess Cost for Instructed Energy	Imbalance Energy
Daily	499	Interest due SC	Misc
Daily	502	Generation Deviation Effective Price	Imbalance Energy
Daily	503	Load Deviation Effective Price	Imbalance Energy
Daily	505	Import Deviation Effective Price	Imbalance Energy
Daily	547	Uninstructed Deviation Penalty Charges Due ISO	Penalties
Daily	1003	Regulation Energy Payment Adjustment	Adjustments
Daily	1004	Over-Generation Payment Due SC	Reliability
Daily	1010	Neutrality Adjustment Charge/Refund	Imbalance Energy
Daily	1011	Ancillary Service Rational Buyer Adjustment	Ancillary Services
Daily	1012	RMR Preemption Revenue Allocation	RMR
Daily	1013	REPA Cash Neutrality Charge	Reliability
Daily	1030	No Pay Provision Market Refund	No Pay
Daily	1061	Distribution of Preempted Spinning Reserve	RMR
Daily	1062	Distribution of Preempted Non-Spinning Reserve	RMR
Daily	1064	Distribution of Preempted Replacement Reserve	RMR
Daily	1065	Distribution of Preempted Regulation Up	Ancillary Services
Daily	1066	Distribution of Preempted Regulation Down	Ancillary Services
Daily	1104	Over-Generation Payment Due ISO	Reliability
Daily	1210	Existing Contracts Cash Neutrality Charge/Refund	Misc
Daily	1277	Real-time Intra-zonal Congestion Charge/Refund	Imbalance Energy
Daily	1278	Alloc of AboveMCP Cost for Real-Time Non-Mkt Dsptch	Excess Costs
Daily	1303	Supplemental Reactive Energy due ISO	Reliability
Daily	1401	Imbalance Energy Offset	Imbalance Energy
Daily	1407	Deviation Penalty for Positive Uninstructed Deviation	Penalties
Daily	1470	Neutrality Charge for UDP Penalties	Penalties
Daily	1471	Excess Cost Neutrality Settlement	Excess Costs
Daily	1481	Excess Cost Allocation - Neutrality Adjustment	Excess Costs
Daily	1487	Energy Exchange Program Neutrality Adjustment	Adjustments
Daily	1680	Allocation of Bid Cost Recovery	Reliability
Daily	1999	Rounding Charge/Refund	Misc
Daily	2009	ISO/SC Distribution/Allocation	Misc
Daily	2010	Finance Charges	Misc
Daily	2020	Must Run due ISO	Misc
Daily	2407	Deviation Penalty for Negative Uninstructed Deviation	Penalties
Daily	2900	CONTINGENCY-Net Manual Market Invoice	Misc
Daily	4141	No Pay Settlement for Spin Capacity	No Pay
Daily	4142	No Pay Settlement for Non Spin Capacity	No Pay
Daily	4144	No Pay Settlement for Replacement Reserve Capacity	No Pay
Daily	4271	Reliability Excess Cost Settlement - Due SC	Imbalance Energy
Daily	4272	OOM Congestion Excess Cost Settlement - Due SC	Imbalance Energy
Daily	4401	Instructed Energy Settlement	Imbalance Energy

Frequency	Charge Type	Charge Type Description	Service Type
Daily	4406	Settlement of Unaccounted for Energy	Imbalance Energy
Daily	4407	Uninstructed Energy Settlement	Imbalance Energy
Daily	4410	Unscheduled RMR Energy	Imbalance Energy
Daily	4450	Transmission Loss Settlement	Imbalance Energy
Daily	4470	Negative Uninstructed Deviation Penalty	Penalties
Daily	4480	Positive Uninstructed Deviation Penalty	Penalties
Daily	4481	Settlement of Excess Cost - Due SC	Imbalance Energy
Daily	4487	Allocation of Excess Cost - Due ISO	Imbalance Energy
Daily	4660	Hrly Pre Dispatch Bid Cost Recovery Settlement	Excess Costs
Daily	4680	Settlement of Bid Cost Recovery	Excess Costs
Daily	4999	Neutrality Adjustment	Adjustments
Daily	5900	Shortfall Receipt	Misc
Daily	5910	Shortfall Allocation	Misc
Daily	5999	FERC Interest	Misc
Daily	6601	Communication Fees	Misc
Daily	6602	Training Fees	Misc
Daily	6603	Miscellaneous Fees	Misc
Daily	6604	OSAT Training Revenues	Misc
Daily	6605	Metering Training Revenues	Misc
Daily	6606	WSCC Revenues	Misc
Daily	6607	Detailed Wheeling Spreadsheet Fees	Misc
Daily	6608	Archived Settlement Statements Retrieval Fee	Misc
Daily	6609	Station Power Fee	Misc
Daily	6610	Station Power Fee Allocation	Misc
Daily	6611	Security Refund	Misc
Daily	6612	ISO Services for GCP	Misc
Daily	6616	FTR Auction	Misc
Daily	6701	Market Invoice	Misc
Daily	6702	GMC Invoice	Misc
Daily	6703	FERC Invoice	Misc
Monthly	7	Demand Relief Monthly Payment	Misc
Monthly	117	Demand Relief Monthly Charge	Misc
Monthly	302	Ex-Post Supplemental Reactive Power due TO	Reliability
Monthly	354	Wheeling Refund due TO	Wheeling
Monthly	372	High Voltage Access Charge due ISO	TAC
Monthly	374	High Voltage Access Revenue due PTO	TAC
Monthly	382	High Voltage Wheeling Charge due ISO	Wheeling
Monthly	383	Low Voltage Wheeling Charge due ISO	Wheeling
Monthly	384	High Voltage Wheeling Revenue due TO	Wheeling
Monthly	385	Low Voltage Wheeling Revenue due TO	Wheeling
Monthly	550	FERC Fees	FERC Fees
Monthly	591	Emissions Cost Recovery	Uplift Fees
Monthly	592	Start-Up Cost Recovery	Uplift Fees
Monthly	593	Emissions Cost Due Trustee	Uplift Fees
Monthly	594	Start-Up Costs Due Trustee	Uplift Fees
Monthly	595	Minimum Load Cost Allocation Due ISO	Reliability
Monthly	691	Emission Cost Payment	Uplift Fees

Frequency	Charge Type	Charge Type Description	Service Type
Monthly	692	Startup Cost Payment	Uplift Fees
Monthly	695	Minimum Load Cost Compensation Due SC	Reliability
Monthly	701	Forecasting Service Fee	Misc
Monthly	702	Forecasting Service Fee Allocation	Misc
Monthly	711	Intermittent Resources Net Deviations	Imbalance Energy
Monthly	721	Intermittent Resources Net Deviation Alloc Charge	Imbalance Energy
Monthly	731	Intermittent Resources Uninstructed Deviation	Imbalance Energy
Monthly	790	Market Transaction Bill Period Adjustment	Adjustments
Monthly	791	Grid Management Charge Bill Period Adjustment	Adjustments
Monthly	792	FERC Fee Bill Period Adjustment	Adjustments
Monthly	793	Transmission Access Charge Refund Bill Period Adj	Adjustments
Monthly	1001	Black start due BA	Reliability
Monthly	1101	Black Start Capacity due ISO	Reliability
Monthly	1120	Est. Summer Reliab. Contract Capacity Pymt/Charge	Reliability
Monthly	1121	Act. Summer Reliab. Contract Capacity Pymt/Charge	Reliability
Monthly	1302	Long Term Voltage Support Contract due ISO	Reliability
Monthly	1353	Black Start Energy due ISO	Reliability
Monthly	1591	EP Penalty Charge, due CAISO trustee	Penalties
Monthly	1592	EP Penalty Allocation Payment	Penalties
Monthly	1593	EP Penalty/Alloc for under/over	Penalties
Monthly	1691	MLCC Neutrality Allocation	Reliability
Monthly	1697	MLCC Tier 1 Allocation	Reliability
Monthly	1698	MLCC Reliability Service Cost Allocation	Reliability
Monthly	1699	MLCC Inter-Zonal Congestion Allocation	Reliability
Monthly	2999	Interest due SC	Misc
Monthly	3010	Termination Fee	Adjustments
Monthly	3020	Termination Fee	Adjustments
Monthly	3101	Black Start Capacity due BA	Reliability
Monthly	3302	Supplemental Reactive Energy due SC	Reliability
Monthly	3303	Long Term Voltage Support due BA	Reliability
Monthly	3351	Grid Management Charge Adjustment Charge/Refund	Adjustments
Monthly	3372	High Voltage Access Charge Adj - Due ISO	Adjustments
Monthly	3374	High Voltage Access Charge Adj - Due PTO	Adjustments
Monthly	3382	High Voltage Wheeling Access Charge Adj - Due ISO	Adjustments
Monthly	3383	Low Voltage Wheeling Access Charge Adj - Due ISO	Adjustments
Monthly	3384	High Voltage Wheeling Access Charge Adj - Due PTO	Adjustments
Monthly	3385	Low Voltage Wheeling Access Charge Adj - Due PTO	Adjustments
Monthly	3472	Demand Relief Energy Payment	Misc
Monthly	3473	Discretionary Load Curtailment Payment	Misc
Monthly	3482	Demand Relief Energy Charge	Misc
Monthly	3483	Discretionary Load Curtailment Charge	Misc

Frequency	Charge Type	Charge Type Description	Service Type
Monthly	3999	Interest and Penalty	Misc
Monthly	4695	Settlement of Minimum Load Cost Comp - Due SC	Reliability
GMC	4501	Core Reliability Services Non-Coincident Peak	GMC
GMC	4502	Core Reliability Services Non-Coincident Off-Peak	GMC
GMC	4503	Core Reliability Services Exports	GMC
GMC	4504	Core Reliability Svcs/Energy Trans Svcs Mojave	GMC
GMC	4505	Energy Transmission Services Net Energy	GMC
GMC	4506	Energy Transmission Services Deviations	GMC
GMC	4511	Forward Scheduling	GMC
GMC	4512	Forward Scheduling Inter-SC Trades	GMC
GMC	4513	Forward Scheduling Path 15 Inter SC Trades	GMC
GMC	4522	Congestion Management	GMC
GMC	4534	Market Usage Ancillary Services	GMC
GMC	4535	Market Usage Instructed energy	GMC
GMC	4536	Market Usage Uninstructed Energy	GMC
GMC	4575	Settlements, Metering, Client Relations	GMC

APPENDIX 2: Template for Determination of an Initial Financial Security Posting Amount

California ISO
Simplified Calculation of Initial Security Amount

Average Hourly Load	4.0	MWh	<------INPUT
Average Hourly Generation	5.4	MWh	<------INPUT
Total Daily Load / Generation	96.0		

	Billable MWh	Price	Total
Ancillary Services	5	$ 9.764	$ 47
FERC Fee	96	$ 0.038	$ 4
Grid Management Charge	165	$ 0.743	$ 123
Imbalance Energy	(25)	$ 44.233	$ (1,087)
Interzonal Congestion	40	$ 0.672	$ 27
Reliability / Minimum Load Cost Compensation	96	$ 0.765	$ 73
Reliability Must Run Generation	96	$ 0.004	$ 0
Uplift Charges	96	$ 0.042	$ 4
Wheeling Charges	96	$ 0.101	$ 10
Total Daily Charges / Daily Security Deposit			$ (800)
Level Period 102 day Security Deposit Posting Requirement			$ (81,579)

Assumptions:

MWh Percentages		
A/S % of Load		5.02%
Net Imbalance Energy Percentage		4.00%
Congestion % of Load		41.25%
Per MWh Costs		
Ancillary Services	$	9.764
FERC Fee	$	0.038
Grid Management Charge	$	0.743
Imbalance Energy	$	44.233
Interzonal Congestion	$	0.672
Reliability / Minimum Load Cost Compensation	$	0.765
Reliability Must Run Generation	$	0.004
Uplift Charges	$	0.042
Wheeling Charges	$	0.101

Note:
Settlement calendar longest number of outstanding days is 95.
The ISO adds 7 days to the estimation to allow for administrative needs and communications to / from SC.

Tab 1 – Credit Policy Compliance Filing Alternative Language and

Interim Reliability Requirements Program Proposed Sheet Designations

IMPORTANT NOTICE:

This tab contains language for Section 12 and Appendix A that the ISO has proposed as alternative language in the Credit Policy Compliance Filing (ER06-700) made on July 11, 2006. This language has not yet been approved by FERC.

Also included in this tab are the proposed sheet designations from the Interim Reliability Requirements Program Docket (ER06-723), if FERC approves the ISO's alternative language in the Credit Policy Compliance Filing.

12 CREDITWORTHINESS.

12.1 Credit Requirements.

The creditworthiness requirements in this section apply to the ISO's acceptance of Schedules, to all transactions in an ISO Market, to the payment of charges pursuant to the ISO Tariff (including the Grid Management Charge), and to establish credit limits for participation in any ISO auction of FTRs. Each Market Participant (including each Scheduling Coordinator, UDC, or MSS) or FTR Bidder shall secure its financial transactions with the ISO (including its participation in any auction of FTRs) by maintaining an Unsecured Credit Limit and/or by posting Financial Security, the level of which constitutes the Market Participant's or FTR Bidder's Financial Security Amount. For each Market Participant or FTR Bidder, the sum of its Unsecured Credit Limit and its Financial Security Amount shall represent its Aggregate Credit Limit. Each Market Participant or FTR Bidder shall have the responsibility to maintain an Aggregate Credit Limit that is at least equal to its Estimated Aggregate Liability.

12.1.1 Unsecured Credit Limit.

Each Market Participant or FTR Bidder requesting an Unsecured Credit Limit shall submit an application to the ISO in the form specified on the ISO Home Page. The ISO shall determine the Unsecured Credit Limit for each Market Participant or FTR Bidder in accordance with the procedures set forth in the ISO Credit Policy & Procedures Guide posted on the ISO Home Page. The maximum Unsecured Credit Limit for any Market Participant or FTR Bidder shall be $250 million. In accordance with the procedures described in the ISO Credit Policy & Procedures Guide, each Market Participant or FTR Bidder requesting or maintaining an Unsecured Credit Limit is required to submit to the ISO or its agent financial statements and other information related to its overall financial health as directed by the ISO. Each Market Participant or FTR Bidder is responsible for the timely submission of its latest financial statements as well as other information that may be reasonably necessary for the ISO to conduct its evaluation. The ISO shall determine the Unsecured Credit Limit for each Market Participant or FTR Bidder as described in subsections (a), (b), (c), and (d) below:

(a) For a Market Participant or FTR Bidder that is a Rated Public/Private Corporation, the Unsecured Credit Limit shall be the lesser of $250 million or an amount equal to the Market Participant's or FTR Bidder's Tangible Net Worth (TNW) multiplied by a calculated percentage of TNW. The allowable TNW percentage is determined with reference to 50 percent (50%) of the Market Participant's or FTR Bidder's Credit Rating Default Probability and 50 percent (50%) of the MKMV Default Probability.

(b) For a Market Participant or FTR Bidder that is an Unrated Public/Private Corporation, the Unsecured Credit Limit shall be the lesser of $250 million or an amount equal to the Market Participant's or FTR Bidder's Tangible Net Worth (TNW) multiplied by a calculated percentage of TNW. The allowable TNW percentage is determined with reference to 100 percent of the MKMV Default Probability.

(c) For a Market Participant or FTR Bidder that is a Rated Governmental Entity, the Unsecured Credit Limit shall be the lesser of $250 million or an amount equal to the Market Participant's or FTR Bidder's Net Assets (NA) multiplied by a calculated percentage of NA. The allowable NA percentage is determined with reference to 100 percent of the Market Participant's or FTR Bidder's Credit Rating Default Probability.

As to each of the types of entities listed in subsections (a), (b), and (c) above, the ISO will use the following eight-step process to calculate the entity's Unsecured Credit Limit: (1) the ISO will obtain the Market Participant's or FTR Bidder's credit rating(s) from NRSROs; (2) the ISO will calculate the Market Participant's or FTR Bidder's Average Rating Default Probability from NRSRO ratings; (3) the ISO will obtain the Market Participant's or FTR Bidder's MKMV Default Probability, if available; (4) the ISO will create a composite default probability for the Market Participant or FTR Bidder based on the results of steps (2) and (3) above; (5) the ISO will calculate a maximum allowable percentage of Tangible Net Worth or Net Assets for the Market Participant or FTR Bidder based on the results of step (4) above; (6) the ISO will obtain the Market Participant's or FTR Bidder's Tangible Net Worth or Net Assets from its financial statements; (7) the ISO will determine a preliminary Unsecured Credit Limit by multiplying the results of step (5) and step (6) above; and (8) if warranted, the ISO will adjust the preliminary Unsecured

Credit Limit downward by up to 100%, based on the ISO's review of qualitative and quantitative factors that relate to an entity's overall financial health and its ability to meet its financial obligations (as described in Section 12.1.1.1).

(d) For a Market Participant or FTR Bidder that is an Unrated Governmental Entity, the Unsecured Credit Limit shall be the lesser of $250 million or an amount equal to a specified percentage of the Market Participant's or FTR Bidder's Net Assets if the Market Participant or FTR Bidder has a minimum of $25 million in Net Assets and its Times Interest Earned, Debt Service Coverage and Equity to Assets ratios (as those ratios are defined in Section A-2.3 of the ISO Credit Policy & Procedures Guide) meet or exceed minimums specified in the ISO Credit Policy & Procedures Guide.

As a result of the ISO's credit evaluation, a Market Participant or FTR Bidder may be given an Unsecured Credit Limit by the ISO or denied an Unsecured Credit Limit with the ISO. Following the initial application and the establishment of an Unsecured Credit limit, the ISO will review each Market Participant's or FTR Bidder's Unsecured Credit Limit on a quarterly basis, unless that entity does not prepare quarterly statements, in which case the review will occur on an annual basis, and no entity shall be required to submit a new application. In addition, the ISO may review the Unsecured Credit Limit for any Market Participant or FTR Bidder whenever the ISO becomes aware of information that could indicate a Material Change in Financial Condition. In the event the ISO determines that the Unsecured Credit Limit of a Market Participant or FTR Bidder must be reduced as a result of a subsequent review, the ISO shall notify the Market Participant or FTR Bidder of the reduction, and shall, upon request, also provide the Market Participant or FTR Bidder with a written explanation of why the reduction was made.

12.1.1.1 Qualitative and Quantitative Credit Strength Indicators.

In determining a Market Participant's or FTR Bidder's Unsecured Credit Limit, the ISO may rely on information gathered from financial reporting agencies, the general/financial/energy press, and provided by the Market Participant or FTR Bidder to assess its overall financial health and its ability to meet its financial obligations. Information considered by the ISO in this process may include the following qualitative factors:

a) Applicant's history;

b) Nature of organization and operating environment;

c) Management;

d) Contractual obligations;

e) Governance policies;

f) Financial and accounting policies;

g) Risk management and credit policies;

h) Market risk including price exposures, credit exposures and operational exposures;

i) Event risk; and

j) The state or local regulatory environment.

Material negative information in these areas may result in a reduction of up to 100% in the Unsecured Credit Limit that would otherwise be granted based on the eight-step process described in Section 12.1.1. A Market Participant or FTR Bidder, upon request, will be provided a written analysis as to how the provisions in Section 12.1.1 and this section were applied in setting its Unsecured Credit Limit.

12.1.1.2 Financial Statements.

Market Participants and FTR Bidders requesting unsecured credit are required to provide financial statements so that a credit review can be completed. Based on availability, the Market Participant or FTR Bidder must submit a financial statement for the most recent financial quarter, as well as audited financial statements for the most recent three fiscal years, or the period of existence of the Market Participant or FTR Bidder, if shorter, to the ISO or the ISO's designee. If audited financial statements are not available, financial statements, as described below, should be submitted, signed and attested to by an officer of the Market Participant or FTR Bidder as a fair representation of the financial condition of the Market Participant or FTR Bidder in accordance with generally accepted accounting principles. The information should include, but is not limited to, the following:

a. If publicly traded:

i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively

ii. Form 8-K reports, if any

b. If privately held or governmentally owned:

i. Management's Discussion & Analysis (if available)

ii. Report of Independent Accountants (if available)

iii. Financial Statements, including:

- Balance Sheet
- Income Statement
- Statement of Cash Flows
- Statement of Stockholder's Equity

iv. Notes to Financial Statements

If the above information is available electronically on the Internet, the Market Participant or FTR Bidder may indicate in written or electronic communication where such statements are located for retrieval by the ISO or the ISO's designee.

12.1.1.3 Determination of Unsecured Credit Limits for Affiliates.

If any Market Participant or FTR Bidder requesting or maintaining an Unsecured Credit Limit is affiliated with one or more other entities subject to the credit requirements of this Section 12, the ISO may consider the overall creditworthiness and financial condition of such Affiliates when determining the applicable Unsecured Credit Limit. The ISO may determine that the maximum Unsecured Credit Limit specified in Section 12.1.1 applies to the combined activity of such Affiliates. In the event the ISO determines that the maximum Unsecured Credit Limit applies to the combined activity of the Affiliates and the Market Participant, the ISO shall inform the Market Participant in writing.

12.1.1.4 Notification of Material Change in Financial Condition.

Each Market Participant or FTR Bidder shall notify the ISO in writing of a Material Change in Financial Condition, within five (5) Business Days of when the Material Change in Financial Condition is known or reasonably should be known by the Market Participant or FTR Bidder. The provision to the ISO of a copy of a Form 10-K, 10-Q, or Form 8-K filed with the U.S. Securities and Exchange Commission shall satisfy

the requirement of notifying the ISO of such Material Change in Financial Condition. Alternatively, the Market Participant may direct the ISO to the location of the information on their company website or the website of the U.S. Securities & Exchange Commission.

12.1.2 Financial Security and Financial Security Amount.

A Market Participant or FTR Bidder that does not have an Unsecured Credit Limit, or that has an Unsecured Credit Limit that is less than its Estimated Aggregate Liability, shall post Financial Security that is acceptable to the ISO and that is sufficient to ensure that its Aggregate Credit Limit (*i.e.*, the sum of its Unsecured Credit Limit and Financial Security Amount) is equal to or greater than its Estimated Aggregate Liability. The Financial Security posted by a Market Participant or FTR Bidder may be any combination of the following types of Financial Security provided in favor of the ISO and notified to the ISO under Section 12.3:

(a) an irrevocable and unconditional letter of credit issued by a bank or financial institution that is reasonably acceptable to the ISO;

(b) an irrevocable and unconditional surety bond issued by an insurance company that is reasonably acceptable to the ISO;

(c) an unconditional and irrevocable guaranty issued by a company that is reasonably acceptable to the ISO;

(d) a cash deposit standing to the credit of the ISO in an interest-bearing escrow account maintained at a bank or financial institution that is reasonably acceptable to the ISO;

(e) a certificate of deposit in the name of the ISO issued by a bank or financial institution that is reasonably acceptable to the ISO;

(f) a payment bond certificate in the name of the ISO issued by a bank or financial institution that is reasonably acceptable to the ISO; or

(g) a prepayment to the ISO.

Financial Security instruments as listed above shall be in such form as the ISO may reasonably require from time to time by notice to Market Participants or FTR Bidders, or in such other form as has been evaluated and approved as reasonably acceptable by the ISO. The ISO shall publish and maintain standardized forms related to the types of Financial Security listed above on the ISO Home Page. The ISO shall require the use of standardized forms of Financial Security to the greatest extent possible.

12.1.2.1 Additional Procedures Regarding Certain Types of Financial Security.

(a) Unconditional and irrevocable guaranties: In those cases where a Market Participant or FTR Bidder is a subsidiary or affiliate of another entity and would like to utilize the consolidated financial statements and other relevant information of that entity for obtaining credit, a signed corporate guaranty is required. A guarantor would be considered reasonably acceptable and a corresponding Financial Security Amount would be set based on the guarantor's credit evaluation according to the same procedures that apply to the credit evaluation of a Market Participant or FTR Bidder.

(b) Cash deposits standing to the credit of the ISO in interest-bearing escrow accounts: Interest on a cash deposit standing to the credit of the ISO in an interest-bearing escrow account will accrue to the Market Participant's or FTR Bidder's benefit and will be added to the Market Participant's or FTR Bidder's prepayment account on a monthly basis. Should a Market Participant or FTR Bidder become delinquent in payments, the Market Participant's or FTR Bidder's outstanding account balance will be satisfied using deposited funds. The Market Participant or FTR Bidder must take care to replenish used funds to ensure that its Aggregate Credit Limit continues to exceed its Estimated Aggregate Liability.

(c) Prepayments to the ISO: Prepayments to the ISO will be held in an interest-bearing account or another investment acceptable to the Market Participant and the ISO, and interest on the investment will accrue at the rate as provided for in the investment. Interest will accrue to the Market Participant's benefit and will be added to the Market Participant's prepayment account on a monthly basis. Due to the additional administrative effort involved in tracking and posting interest on such prepayments, the use of this option is not encouraged.

12.1.2.2 Process for Evaluating Requests to Use Non-Standardized Forms of Financial Security.

A Market Participant or FTR Bidder that seeks permission to use a form for Financial Security other than one or more of the standardized forms posted on the ISO Home Page shall seek such permission in a written request to the ISO that explains the basis for the use of such non-standardized form. The ISO shall have ten (10) Business Days from receipt of such request to evaluate it and determine whether it will be approved as reasonably acceptable. If the ISO does not respond to such request within the ten (10) Business Day period, the request shall be deemed to have been denied. Until and unless the ISO approves the use of a non-standardized form for Financial Security, the Market Participant or FTR Bidder that submitted such request shall be required to use one of the standardized forms for Financial Security described in this Section 12.1.2.

12.1.2.3 Expiration of Financial Security.

Each Market Participant or FTR Bidder shall ensure that the financial instruments it uses for the purpose of providing Financial Security will not expire and thereby cause the Market Participant's or FTR Bidder's Aggregate Credit Limit to fall below the Market Participant's or FTR Bidder's Estimated Aggregate Liability. The ISO will treat a financial instrument that does not have an automatic renewal provision and that is not renewed or replaced within seven (7) days of its date of expiration as being out of compliance with the standards for Financial Security contained in this Section 12 and will deem the value of such financial instrument to be zero, and will draw upon such Financial Security prior to its stated expiration if deemed necessary by the ISO.

12.1.2.4 Risk of Loss of Financial Security Amounts Held and Invested by the ISO.

In accordance with the ISO's investment policy, the ISO will invest each Financial Security Amount of a Market Participant or FTR Bidder only in bank accounts, high-quality money market accounts, and/or U.S. Treasury/Agency securities unless a specific written request is received from the Market Participant or FTR Bidder for a different type of investment and the ISO provides its written consent to such alternative investment. A Market Participant or FTR Bidder that provides a Financial Security Amount that is held and invested by the ISO on behalf of the Market Participant or FTR Bidder will bear all risks that such Financial Security Amount will incur a loss of principal and/or interest as a result of the ISO's investment of such Financial Security Amount.

12.1.3 Self-Supply of UDC Demand.

Notwithstanding anything to the contrary in the ISO Tariff, a Scheduling Coordinator or UDC that is an Original Participating Transmission Owner or is a Scheduling Coordinator for an Original Participating Transmission Owner shall not be precluded by Section 12.3 from scheduling transactions that serve a UDC's Demand from –

(1) a resource that the UDC owns; and

(2) a resource that the UDC has under contract to serve its Demand.

12.1.4 Allocation of Aggregate Credit Limit for FTR Auction Participation.

An FTR Bidder may elect to allocate a portion of its Aggregate Credit Limit toward satisfying the credit requirements for participating in auctions of FTRs, as set forth in Section 36.2.6.

12.1.5 Estimated Aggregate Liability.

The ISO will periodically calculate the Estimated Aggregate Liability of each Market Participant and FTR Bidder, based on all charges and settlement amounts for which such Market Participant or FTR Bidder is liable or reasonably anticipated by the ISO to be liable for pursuant to the ISO Tariff. The Estimated Aggregate Liability for each Market Participant or FTR Bidder shall be determined and applied by the ISO consistent with the procedures set forth in the ISO Credit Policy & Procedures Guide posted on the ISO Home Page. The ISO shall upon request provide each Market Participant or FTR Bidder with information concerning the basis for the ISO's determination of its Estimated Aggregate Liability, and the ISO's determination may be disputed in accordance with the procedures set forth in the ISO Credit Policy & Procedures Guide. The ISO shall compare each Market Participant's or FTR Bidder's Estimated Aggregate Liability against its Aggregate Credit Limit on a periodic basis.

12.2 Review of Creditworthiness.

The ISO may review the creditworthiness of any Market Participant or FTR Bidder which delays or defaults in making payments due under the ISO Tariff and, as a consequence of that review, may require such Market Participant or FTR Bidder, whether or not it an Unsecured Credit Limit, to provide credit support in the form of any of the following types of Financial Security:

(a) an irrevocable and unconditional letter of credit by a bank or financial institution reasonably acceptable to the ISO;

(b) a cash deposit standing to the credit of an interest-bearing escrow account maintained at a bank or financial institution designated by the ISO;

(c) an irrevocable and unconditional surety bond posted by an insurance company reasonably acceptable to the ISO;

(d) a payment bond certificate in the name of the ISO from a financial institution designated by the ISO; or

(e) a prepayment to the ISO.

The ISO may require the Market Participant or FTR Bidder to maintain such Financial Security for at least one (1) year from the date of such delay or default.

12.4 Calculation of Ongoing Financial Security Requirements.

Following the date on which a Market Participant commences trading, if the Market Participant's Estimated Aggregate Liability, as calculated by the ISO, at any time exceeds its Aggregate Credit Limit, the ISO shall direct the Market Participant to post an additional Financial Security Amount within five (5) Business Days that is sufficient to ensure that the Market Participant's Aggregate Credit Limit is at least equal to its Estimated Aggregate Liability. The ISO shall also notify a Market Participant if at any time its Estimated Aggregate Liability exceeds 90% of its Aggregate Credit Limit. For the purposes of calculating the Market Participant's Estimated Aggregate Liability, the ISO shall include (1) outstanding charges for Trading Days for which Settlement data is available, and (2) an estimate of charges for Trading Days for which Settlement data is not yet available. To estimate charges for Trading Days for which Settlement data is not yet available, the ISO will consider available historical Settlement data, and other available operational and market data as described in the ISO Credit Policy & Procedures Guide posted on the ISO Home Page.

12.4.1 Review of an ISO Request for an Additional Financial Security Amount.

A Market Participant has five (5) Business Days to review an ISO request for additional Financial Security and submit proposed changes that must be agreed to by the ISO. Within the five (5) Business Days, the Market Participant must either demonstrate to the ISO's satisfaction that the ISO's Financial Security request is entirely or partially unnecessary, or post the required Financial Security Amount calculated by the ISO. If the ISO and the Market Participant are unable to agree on the appropriate level of Financial Security during the five (5) Business Day review period, the Market Participant must post the additional Financial Security and may continue with the dispute process described in Section 12.4.2. Any excess Financial Security amounts will be returned to the Market Participant if the dispute process finds in favor of the Market Participant.

12.4.2 Dispute Process Regarding an ISO Request for an Additional Security Amount.

Market Participants may dispute the Estimated Aggregate Liability calculated by the ISO and, as a result, the ISO may reduce or cancel a requested Financial Security adjustment. The following steps are

required for a Market Participant to dispute a Financial Security request resulting from the ISO's calculation of Estimated Aggregate Liability:

(1) Request by the Market Participant to review the ISO calculation.

(2) A reasonable and compelling situation presented, as determined by the Market Participant's ISO client representative.

(3) Documentation of facts and circumstances that evidence that the ISO's calculation of Estimated Aggregate Liability results in an excessive and unwarranted Financial Security posting requirement.

(4) Approval by the ISO Manager and/or Director of Customer Services and Industry Affairs and approval by the ISO Treasurer.

(5) The ISO may decline to adjust the initial Estimated Aggregate Liability, as calculated by the ISO, if the Market Participant has had Financial Security shortfalls in the past 12 months (*i.e.*, it has been shown that the Market Participant's Aggregate Credit Limit at times during the preceding 12 months has been insufficient to cover the Market Participant's Estimated Aggregate Liability).

In no such case shall an ISO request for increased Financial Security remain outstanding for more than five (5) Business Days. Either the above process is to be completed within five (5) Business Days from the date of the ISO request for additional Financial Security, or the Market Participant is to post additional Financial Security within the five (5) Business Days and continue this process, which may result in a return of posted Financial Security back to the Market Participant if the results of the dispute process are found to favor the Market Participant.

Factors for consideration in the event this dispute process is utilized include: weighing the risk of using the lower figure to the potential detriment of market creditors if the Market Participant is under-secured and defaults, against the desire not to impose additional potentially unwarranted costs on a Market Participant; equity and consistency of treatment of Market Participants in the dispute process; and the evidentiary value of the information provided by the Market Participant in the dispute process.

12.5 ISO Enforcement Actions Regarding Under-Secured Market Participants.

Following the date on which a Market Participant commences trading, if a Market Participant's Estimated Aggregate Liability, as calculated by the ISO, at any time exceeds its Aggregate Credit Limit, the ISO may take any or all of the following actions:

(a) The ISO may withhold a pending payment distribution.

(b) The ISO may limit trading, which may include rejection of Schedules and/or limiting other ISO market activity. In such case, the ISO shall notify the Market Participant of its action and the Market Participant shall not be entitled to submit further Schedules to the ISO until the Market Participant posts an additional Financial Security Amount that is sufficient to ensure that the Market Participant's Aggregate Credit Limit is at least equal to its Estimated Aggregate Liability.

(c) The ISO may require the Market Participant to post an additional Financial Security Amount in lieu of an Unsecured Credit Limit for a period of time.

(d) The ISO may restrict, suspend, or terminate a Market Participant's Service Agreement.

In addition, the ISO may restrict or suspend a Market Participant's right to schedule or require the Market Participant to increase its Financial Security Amount if at any time such Market Participant's potential additional liability for Imbalance Energy and other ISO charges is determined by the ISO to be excessive by comparison with the likely cost of the amount of Energy scheduled by the Market Participant.

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.
"Area Control Error (ACE)"	The sum of the instantaneous difference between the actual net interchange and the scheduled net interchange between the ISO Control Area and all adjacent Control Areas and the ISO Control Area's frequency correction and time error correction obligations.
Authorized Users	A person or an entity identified as an authorized user in a meter service agreement between the ISO and an ISO Metered Entity or a meter service agreement between the ISO and a SC.
Automatic Mitigation Procedure (AMP)	The market power mitigation procedure described in Attachment A to Appendix P.
Available Transfer Capacity	For a given transmission path, the capacity rating in MW of the path established consistent with ISO and WECC transmission capacity
Average Rating Default Probability (ARDP)	The sum of Credit Rating Default Probabilities divided by the total number of Credit Rating Default Probabilities used.

Control Area Operator	The person responsible for managing the real-time operations of a Control Area.
Converted Rights	Those transmission service rights as defined in Section 16.21A.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.
Credit Rating Default Probability	The 5 Year Median Default Probability based on a rating agency's credit rating as listed in the Credit Rating Default Probabilities table in Section A-2.2 of the ISO Credit Policy & Procedures Guide.
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 0	The Trading Day to which the Settlement Statement or Settlement

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 Change in Financial Condition A change in or potential threat to the financial condition of a Market Participant or FTR Bidder that increases the risk that the Market Participant or FTR Bidder will be unlikely to meet some or all of its financial obligations. The types of Material Change in Financial Condition include but are not limited to the following:

(a) a credit agency downgrade;

(b) being placed on a credit watch list by a major rating agency;

(c) a bankruptcy filing;

(d) insolvency;

(e) the filing of a material lawsuit that could significantly and adversely affect past, current, or future financial results; or

(f) any change in the financial condition of the Market Participant or FTR Bidder which exceeds a five percent (5%) reduction in the Market Participant's or FTR Bidder's tangible net worth or net assets for the Market Participant or FTR Bidder's preceding fiscal year, calculated in accordance with generally accepted accounting practices.

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.

MDAS The ISO's revenue meter data acquisition and processing system.

	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.
Meter Data Exchange Format	The format for submitting Meter Data to the ISO which will be published by the ISO on the ISO Home Page or available on request to the Meter and Data Acquisition Manager, ISO Client Service Department.
Meter Data Request Format	The format for requesting Settlement Quality Meter Data from the ISO which will be published by the ISO on the ISO Home Page or available on request to the Meter and Data Acquisition Manager, ISO Client Service Department.
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.
Metering Facilities	Revenue quality meters, instrument transformers, secondary circuitry, secondary devices, meter data servers, related communication facilities and other related local equipment.
Minimum Load Costs	The costs a Generating Unit incurs operating at minimum load.
MKMV Default Probability	A calculated result of Moody's KMV CreditEdge or RiskCalc software products.
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 4.9.1.
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 40.1.1 of the ISO Tariff.
Nationally Recognized Statistical Rating Organizations (NRSRO)	National credit rating agencies as designated by the U.S. Securities & Exchange Commission.
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 Assets (NA)	For governmental and not-for-profit entities, defined as total assets minus total liabilities.
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 36.4.3 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 36.4.3 FTRs; minus b) Usage Charges that are: i) incurred by the Scheduling Coordinator for the New Participating TO under ISO Tariff Section 27.1.2.1.4 ii) associated with the New Participating TO's Section 36.4.3 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 27.1.2.1.7, 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 36.4.3 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.
Net Output	The gross Energy output from a Generating Unit less the Station Power requirements for such Generating Unit during the Netting Period, or the Energy available to provide Remote Self-Supply from a generating facility in another Control Area during the Netting Period.
Netting Period	A calendar month, representing the interval over which the Net Output of one or more generating resources in a Station Power Portfolio is available to be attributed to the self-supply of Station Power in that Station Power Portfolio.
Network Upgrades	The additions, modifications, and upgrades to the ISO

	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.
Qualifying Facility	A qualifying co-generation or small power production facility recognized by FERC.
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.
Rated Governmental Entity	A municipal utility or state or federal agency that holds an issuer, counterparty, or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Rated Public/Private Corporation	An investor-owned or privately held entity that holds an issuer, counterparty, or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
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 the ISO Tariff, to assist the ISO to maintain reliability of the ISO Controlled Grid and to carry out its functions.

	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.
Tangible Net Worth (TNW)	Total assets minus intangibles (*e.g.*, good will) minus total liabilities.
Tax Exempt Debt	Municipal Tax Exempt Debt or Local Furnishing Bonds.

Energy	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).
Unrated Governmental Entity	A municipal utility or state or federal agency that does not hold an issuer, counterparty, or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Unrated Public/Private Corporation	An investor-owned or privately held entity that does not hold an issuer, counterparty, or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Unsecured Credit Limit	The level of credit established for a Market Participant or FTR Bidder that is not secured by any form of Financial Security, as provided for in Section 12 of the ISO Tariff.
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.
Validation, Estimation and Editing (VEE)	Applies to Meter Data directly acquired by the ISO. Validation is the process of checking the data to ensure that it is contiguous, within pre-defined limits and has not been flagged by the meter. Estimation and Editing is the process of replacing or making complete Meter Data by using data from redundant meters, schedules, PMS or, if necessary, statistical estimation.
Value Added Network (VAN)	A data communications service provider that provides, stores and forwards electronic data delivery services within its network and to subscribers on other VANs. The data is mostly EDI type messages.
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 40.1.6.

Interim Reliability Requirements Program Proposed Sheet Designations

	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.
Nationally Recognized Statistical Rating Organizations (NRSRO)	National credit rating agencies as designated by the U.S. Securities & Exchange Commission.
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 Assets (NA)	For governmental and not-for-profit entities, defined as total assets minus total liabilities.
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 36.4.3 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 36.4.3 FTRs; minus b) Usage Charges that are: i) incurred by the Scheduling Coordinator for the New Participating TO under ISO Tariff Section 27.1.2.1.4 ii) associated with the New Participating TO's Section 36.4.3 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 27.1.2.1.7, 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 36.4.3 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.
Net Output	The gross Energy output from a Generating Unit less the Station Power requirements for such Generating Unit during the Netting Period, or the Energy available to provide Remote Self-Supply from a generating facility in another Control Area during the Netting Period.
Netting Period	A calendar month, representing the interval over which the Net Output of one or more generating resources in a Station Power Portfolio is available to be attributed to the self-supply of Station Power in that Station Power Portfolio.
Net Qualifying Capacity	Qualifying capacity reduced, as applicable, based on: (1) testing and verification; and (2) deliverability restrictions. The Net Qualifying Capacity determination shall be made by the ISO pursuant to the provisions of this ISO Tariff and any applicable manual or procedure.
Network Upgrades	The additions, modifications, and upgrades to the ISO

	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.
Qualifying Capacity	The maximum capacity of a Resource Adequacy Resource. The criteria for calculating Qualifying Capacity from Resource Adequacy Resources may be established by the CPUC or other applicable Local Regulatory Authority and provided to the ISO, or default provisions in Section 40.13 of this ISO Tariff.
Qualifying Facility	A qualifying co-generation or small power production facility recognized by FERC.
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.
Rated Governmental Entity	A municipal utility or state or federal agency that holds an issuer, counterparty, or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Rated Public/Private Corporation	An investor-owned or privately held entity that holds an issuer, counterparty, or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
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 the ISO Tariff, to assist the ISO to maintain reliability of the ISO Controlled Grid and to

	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.
Supply Plan	A submission by a Scheduling Coordinator for a Resource Adequacy Resource in order to satisfy the requirements of Section 40 of this ISO Tariff.
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.
Tangible Net Worth (TNW)	Total assets minus intangibles (*e.g.,* good will) minus total liabilities.
Tax Exempt Debt	Municipal Tax Exempt Debt or Local Furnishing Bonds.

Energy	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).
Un-Recovered Minimum Load Cost	The Un-Recovered Minimum Load Cost for each hour of Waiver Denial Period shall be calculated as the difference between: (1) a resource's Minimum Load Costs as calculated in this Section for the same Settlement Interval and (2) the Imbalance Energy payment for a resource's minimum load energy in the Settlement Interval.
Unrated Governmental Entity	A municipal utility or state or federal agency that does not hold an issuer, counterparty, or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Unrated Public/Private Corporation	An investor-owned or privately held entity that does not hold an issuer, counterparty, or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Unsecured Credit Limit	The level of credit established for a Market Participant or FTR Bidder that is not secured by any form of Financial Security, as provided for in Section 12 of the ISO Tariff.
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.
Validation, Estimation and Editing (VEE)	Applies to Meter Data directly acquired by the ISO. Validation is the process of checking the data to ensure that it is contiguous, within pre-defined limits and has not been flagged by the meter. Estimation and Editing is the process of replacing or making complete Meter Data by using data from redundant meters, schedules, PMS or, if necessary, statistical estimation.
Value Added Network (VAN)	A data communications service provider that provides, stores and forwards electronic data delivery services within its network and to subscribers on other VANs. The data is mostly EDI type messages.
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 40.7.6.
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.
Weekly Peak Demand Forecast	Demand Forecast of the highest Hourly Demand in any hour in a period beginning at the start of the hour ending 0100 on Sunday and ending at the end of the hour ending 2400 the following Saturday, in MW.

Tab 2 – Credit Policy Supplemental Compliance Filing Alternative Language

IMPORTANT NOTICE:

This tab contains language for Section 12 and Appendix A that the ISO has proposed as alternative language in the Credit Policy Supplemental Compliance Filing (ER06-700) made on August 9, 2006. This language has not yet been approved by FERC.

b. If privately held or governmentally owned:

i. Management's Discussion & Analysis (if available)

ii. Report of Independent Accountants (if available)

iii. Financial Statements, including:

- Balance Sheet
- Income Statement
- Statement of Cash Flows
- Statement of Stockholder's Equity

iv. Notes to Financial Statements

If the above information is available electronically on the Internet, the Market Participant or FTR Bidder may indicate in written or electronic communication where such statements are located for retrieval by the ISO or the ISO's designee.

12.1.1.3 Determination of Unsecured Credit Limits for Affiliates.

If any Market Participant or FTR Bidder requesting or maintaining an Unsecured Credit Limit is affiliated with one or more other entities subject to the credit requirements of this Section 12, the ISO may consider the overall creditworthiness and financial condition of such Affiliates when determining the applicable Unsecured Credit Limit. The ISO may determine that the maximum Unsecured Credit Limit specified in Section 12.1.1 applies to the combined activity of such Affiliates. In the event the ISO determines that the maximum Unsecured Credit Limit applies to the combined activity of the Affiliates and the Market Participant, the ISO shall inform the Market Participant in writing.

12.1.1.4 Unsecured Credit Limit for a Local Publicly Owned Electric Utility

A Local Publicly Owned Electric Utility with a governing body having ratemaking authority that has submitted an application for an Unsecured Credit Limit shall be entitled to an Unsecured Credit Limit of one million dollars ($1,000,000) without regard to its Net Assets. Such Local Publicly Owned Electric Utility shall be entitled to request an Unsecured Credit Limit based on Net Assets as provided in Section

12.1.1 of the ISO Tariff in order to establish an Unsecured Credit Limit as the greater of one million dollars ($1,000,000) or the amount determined as provided in Section 12.1.1 of the ISO Tariff. A public entity that is not a Local Publicly Owned Electric Utility is not entitled to an Unsecured Credit Limit of one million dollars ($1,000,000) under this Section but may seek to establish an Unsecured Credit Limit as provided in Section 12.1.1 of the ISO Tariff or any other provision of the ISO Tariff that may apply.

Public entities, including Local Publicly Owned Electric Utilities, that operate through a Joint Powers Agreement, or a similar agreement acceptable to the ISO with the same legal force and effect, shall be entitled to aggregate or assign their Unsecured Credit Limits subject to the following limitations and requirements. A public entity that is a party to a Joint Powers Agreement or similar agreement and that is also participating independently in the ISO's markets with an established Unsecured Credit Limit shall not be entitled to assign or aggregate any portion of its Unsecured Credit Limit that the public entity is using to support financial liabilities associated with its individual participation in the ISO's markets. A Local Publicly Owned Electric Utility that operates through a Joint Powers Agreement or similar agreement that desires to aggregate a portion of its Unsecured Credit Limit that is equal to or less than one million dollars ($1,000,000) with one or more other Local Publicly Owned Electric Utilities that operate through that Joint Powers Agreement or similar agreement or to assign a portion of its Unsecured Credit Limit that is equal to or less than one million dollars ($1,000,000) to the Joint Powers Authority shall be entitled to do so. A Local Publicly Owned Electric Utility that operates through a Joint Powers Agreement or similar agreement that desires to aggregate its Unsecured Credit Limit with one or more other Local Publicly Owned Electric Utilities that operate through that Joint Powers Agreement or similar agreement or to assign a portion of its Unsecured Credit Limit to the Joint Powers Authority that exceeds one million dollars ($1,000,000), and any public entity that is not a Local Publicly Owned Electric Utility that operates through a Joint Powers Agreement or similar agreement that desires to aggregate its Unsecured Credit Limit with one or more other Local Publicly Owned Electric Utilities that operate through that Joint Powers Agreement or similar agreement or to assign any portion of its Unsecured Credit Limit to the Joint Powers Authority, shall provide documentation that is acceptable to the ISO and that demonstrates the Local Publicly Owned Electric Utility or public entity will assume responsibility for the financial liabilities of the

Joint Powers Agency associated with the assigned or aggregated portion of the Unsecured Credit Limit. Such documentation may include a guaranty or similar instrument acceptable to the ISO.

Unsecured Credit Limits established through this section or through Section 12.1.1 of the ISO Tariff shall be subject to the ISO's consideration of the same qualitative factors that apply to all other Market Participants and FTR Bidders as set forth in Section 12.1.1.1 of the ISO Tariff and, accordingly, the ISO may adjust their Unsecured Credit Limits pursuant to Section 12.1.1 of the ISO Tariff.

12.1.1.5 Unsecured Credit Limit for an Unrated Governmental Entity that Receives Appropriations from the Federal Government or a State Government

An Unrated Governmental Entity that receives appropriations from the federal government or a state government that has submitted an application for an Unsecured Credit Limit shall be entitled to an Unsecured Credit Limit of the lower of the cap of 250 million dollars ($250,000,000) or the amount appropriated by the federal or relevant state government for the purpose of procuring energy and energy-related products and services for the applicable fiscal year. The Unrated Governmental Entity seeking to establish an Unsecured Credit Limit pursuant to this section shall provide documentation establishing its annual appropriations. Unsecured Credit Limits established pursuant to this section or through Section 12.1.1 of the ISO Tariff shall be subject to the ISO's consideration of the same qualitative factors that apply to all other Market Participants and FTR Bidders as set forth in Section 12.1.1.1 of the ISO Tariff and, accordingly, the ISO may adjust their Unsecured Credit Limits pursuant to Section 12.1.1 of the ISO Tariff.

12.1.1.6 Notification of Material Change in Financial Condition.

Each Market Participant or FTR Bidder shall notify the ISO in writing of a Material Change in Financial Condition, within five (5) Business Days of when the Material Change in Financial Condition is known or reasonably should be known by the Market Participant or FTR Bidder. The provision to the ISO of a copy of a Form 10-K, 10-Q, or Form 8-K filed with the U.S. Securities and Exchange Commission shall satisfy

ISP (Internet Service Provider)	An independent network service organization engaged by the ISO to establish, implement and operate WEnet.
Joint Powers Agreement	An agreement governing a Joint Powers Authority that is subject to the California Joint Exercise of Powers Act (California Government Code, Section 6500, *et seq.*).
Joint Powers Authority	An authority authorized by law through which two or more public entities jointly exercise their powers.
Large Generating Facility	A Generating Facility having a Generating Facility Capacity of more than 20 MW.
Line Loss Correction Factor	The line loss correction factor as set forth in the Technical Specifications.
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 unique to the transmission systems of each of the PTOs established at the later of: (1) ISO Operations Date, or (2) the date upon which a New Participating TO places its facilities under

ISO Website	The ISO internet home page at http://www.caiso.com or such other internet address as the ISO shall publish from time to time.
ISP (Internet Service Provider)	An independent network service organization engaged by the ISO to establish, implement and operate WEnet.
Joint Powers Agreement	An agreement governing a Joint Powers Authority that is subject to the California Joint Exercise of Powers Act (California Government Code, Section 6500, *et seq.*).
Joint Powers Authority	An authority authorized by law through which two or more public entities jointly exercise their powers.
Large Generating Facility	A Generating Facility having a Generating Facility Capacity of more than 20 MW.
Line Loss Correction Factor	The line loss correction factor as set forth in the Technical Specifications.
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-Serving Entity (LSE)	Any entity (or the duly designated agent of such an entity, including, e.g. a Scheduling Coordinator), including a load aggregator or power marketer; (i) serving End Users within the ISO Control Area and (ii) that has been granted authority or has an obligation pursuant to California State or local law, regulation, or franchise to sell electric energy to End Users located within the ISO Control Area or (iii) is a Federal Power Marketing Authority that serves retail Load.
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.